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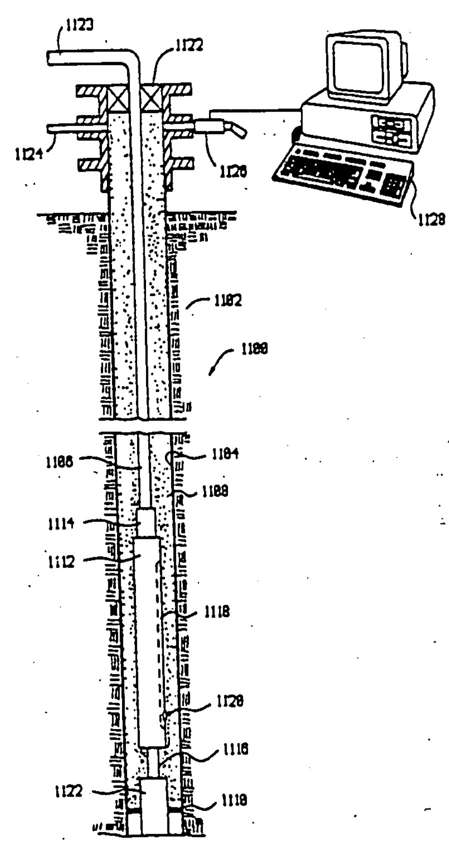
(54) Title: METHOD AND APPARATUS FOR IMPROVED COMMUNICATION IN A WELLBORE UTILIZING ACOUSTIC SIGNALS

(57) Abstract

A method and apparatus for communication with downhole wellbore tools using acoustic transmission techniques is disclosed. A completion fluid (1108) disposed in the wellbore (1100) acts as the transmission medium between a surface acoustic transducer (1126) and a downhole acoustic transducer (1112). The transducers may be used to actuate a downhole tool from the surface or to receive data or communication at the surface from a downhole tool.



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METHOD AND APPARATUS FOR IMPROVED COMMUNICATION IN A WELLBORE UTILIZING ACOUSTIC SIGNALS

BACKGROUND OF THE INVENTION

1. Field of the Invention:

The present invention relates in general to a system for communicating in a wellbore, and in particular to a system for communicating in a wellbore utilizing acoustic signals.

2. Description of the Prior Art:

At present, the oil and gas industry is expending significant amounts on research and development toward the problem of communicating data and control signals within a wellbore. Numerous prior art systems exist which allow for the passage of data and control signals within a wellbore, particularly during logging operations. However, a non-invasive communication technology for completion and production operations has not yet been perfected. The communication systems which may eventually be utilized during completion operations must be especially secure, and not susceptible to false actuation. This is true because many events occur during completion operations, such as the firing of perforating guns, the setting of liner hangers and the like, which are either impossible or difficult to reverse. This is, of course, especially true for perforation operations. If a perforating gun were to inadvertently or unintentionally discharge in a region of the wellbore which does not need perforations, considerable remedial work must be performed. In complex perforation operations, a plurality of perforating guns are carried by a completion string. It is especially important that the command signal which is utilized to

discharge one perforating gun not be confused with command signals which are utilized to actuate other perforating guns.

BRIEF DESCRIPTION OF THE DRAWINGS

The novel features believed characteristic of the invention are set forth in the appended claims. The invention itself, however, as well as a preferred mode of use, further objectives and advantages thereof, will best be understood by reference to the following detailed description of an illustrative embodiment when read in conjunction with the accompanying drawings, wherein:

Figure 1 is a simplified and schematic depiction of the present invention;

Figure 2 is an overall schematic sectional view illustrating a potential location within a borehole of one alternative acoustic tone generator;

Figure 3 is an enlarged schematic view of a portion of the arrangement shown in **Figure 2**;

Figure 4 is a fragmentary longitudinal section view of a transducer constructed in accordance with the present invention;

Figure 5 is an enlarged sectional view of a portion of the construction shown in **Figure 4**;

Figure 6 is a transverse sectional view, taken on a plane indicated by the lines 5-5 in **Figure 5**;

Figure 7 is a partial, somewhat schematic sectional view showing the magnetic circuit provided by the implementation illustrated in **Figures 4-6**;

Figure 8A is a schematic view corresponding to the implementation of the invention shown in **Figures 4-6**, and **Figure 8B** is a variation on such implementation;

Figures 9 through **12** illustrate various alternate constructions;

Figure 13 illustrates in schematic form a preferred combination of such elements;

Figure 14 is an overall somewhat diagrammatic sectional view illustrating an implementation of the invention;

Figure 15 is a block diagram of a preferred embodiment of the invention;

Figure 16 is a flow chart depicting the synchronization process of the downhole acoustic transceiver portion of the preferred embodiment of **Figure 15**;

Figure 17 is a flowchart representation of the channel characterization and data transmission operations;

Figures 18A, 18B, and 18C depict the synchronization signal structure;

Figure 19 is a detailed block diagram of the downhole acoustic transceiver;

Figure 20 is a detailed block diagram of the surface acoustic transceiver; and

Figure 21 depicts the second synchronization signals and the resultant correlation signals;

Figure 22 is a timing and signal transmission diagram for a software implemented embodiment of the present invention;

Figure 23 is a flowchart depiction of the basic steps utilized to implement the software implemented embodiment of **Figure 22**;

Figure 24 depicts an acoustic tone generator in accordance with a hardware embodiment of the present invention;

Figures 25 and **26** are circuit diagrams for an acoustic tone receiver of the hardware embodiment of the present invention;

Figure 27 is a block diagram depiction of an alternative embodiment of the acoustic tone receiver;

Figure 28 is a flowchart of the operation of the embodiment of **Figure 29**;

Figure 29A through **Figure 29G** are timing charts which illustrate the operation of the acoustic tone receiver and acoustic tone generator;

Figure 31 and **Figure 32** depict an exemplary application of the acoustic tone activator of the present invention;

Figure 32 is a flow chart representation of the computer control of the acoustic tone generator;

Figure 33 is a longitudinal section view of a gas generating end device which may be activated by the acoustic tone activator of the present invention;

Figures 34 through **38** are longitudinal and cross section views of the gas generating end devices;

Figures 39 through **43** are simplified longitudinal views of exemplary end devices; and

Figure 44A is a pictorial representation of the utilization of the present invention during completion and drill stem testing operations;

Figure 44B is another pictorial representation of the utilization of the present invention during completion and drill stem testing operations;

Figure 45 is a block diagram representation of the surface and subsurface systems utilized in the present invention during completion and drill stem testing operations;

Figure 46 is a block diagram representation of one particular embodiment of the present invention which includes redundancy in the electronic and processing components in order to increase system reliability;

Figure 47 is a data flow representation of utilization of the present invention during completion and drill stem testing operations;

Figure 48 is a graphical representation of a frequency domain plot of wellbore acoustics, which demonstrates that acoustic devices can be utilized to monitor the flow of fluids into the wellbore;

Figure 49 is a flowchart representation of utilization of the acoustic monitoring in order to determine flow rates;

Figure 50 is a flowchart representation of data processing implemented steps of sensing, monitoring and transmitting data relating to temperature, pressure, and flow during and after drill stem test operations; and

Figure 51 is a flowchart representation of the method of utilizing the present invention during drill stem test operations.

DETAILED DESCRIPTION OF THE INVENTION

The detailed description of the preferred embodiment follows under the following specific topic headings:

1. OVERVIEW OF THE PRESENT INVENTION;
2. ACOUSTIC TONE GENERATOR AND RECEIVER WITH ADAPTABILITY TO COMMUNICATION CHANNELS;
3. ACOUSTIC TONE GENERATOR AND RECEIVER - SOFTWARE VERSION;
4. ACOUSTIC TONE GENERATOR AND RECEIVER - HARDWARE VERSION;

5. APPLICATIONS AND END DEVICES; and

6. LOGGING DURING COMPLETIONS.

1. OVERVIEW OF THE PRESENT INVENTION

The present invention includes several embodiments which can be understood with reference to **Figure 1**.

In its most basic form, the present invention requires that a tubular string **2** be lowered within wellbore **1**. Tubular string **2** carries a plurality of receivers **3**, **5**, each of which is uniquely associated with a particular one of tools **4**, **6**. One or more transmitters **7**, **8**, which may be carried by tubular string **2** at an upborehole location or at a surface location **9** are utilized to send coded messages within wellbore **1**, which are received by the receivers **3**, **5**, decoded, and utilized to activate particular ones of the wellbore tools **4**, **6**, in order to accomplish a particular completion or drill stem test objective.

Before, during, and after the particular wellbore operations are completed, the receivers **3**, **5** are utilized to perform noise logging operations.

The present invention includes two, very different, embodiments of the acoustic activation system.

A very sophisticated system is described in Sections 2 and 3 below, which are entitled:

2. ACOUSTIC TONE GENERATOR AND RECEIVER WITH ADAPTABILITY TO COMMUNICATION CHANNELS; and

3. ACOUSTIC TONE GENERATOR AND RECEIVER - SOFTWARE VERSION.

A more simple hardware version is discussed below in Section 4 which is entitled: ACOUSTIC TONE GENERATOR AND RECEIVER - HARDWARE VERSION.

The operations and uses of either system (software or hardware) are discussed in Section 5, which is entitled: APPLICATIONS AND END DEVICES.

The use of the receivers **3**, **5** to monitor the acoustic events within the wellbore before, during, and after a particular actuation (such as a completion or drill stem test event) is discussed in Section 5 which is entitled: LOGGING DURING COMPLETIONS.

2. ACOUSTIC TONE GENERATOR WITH ADAPTABILITY TO COMMUNICATION CHANNELS

In this particular embodiment, the acoustic tone generator/receiver is a sophisticated acoustic device that can be utilized for two-way communication. One particularly attractive feature of this alternative is the ability to characterize and examine the communication channel in a manner which identifies the optimum frequency (or frequencies) of operation. In accordance with this particular approach, one transmitter/receiver pair is located at the surface, and one transmitter/receiver pair is located in the wellbore. The downhole transmitter/receiver is utilized to identify the optimum operating frequency. Then, the transmitter/receiver that is located at the surface is utilized to generate the acoustic tone command which is utilized to actuate a wellbore tool.

<u>THE TRANSDUCER:</u> The transducer of the present invention will be described with references to **Figures 2** through **21**.

With reference to **Figure 2**, a borehole, generally referred to by the reference numeral **11**, is illustrated extending through the earth **12**. Borehole **11** is shown as a petroleum product completion hole for illustrative purposes. It includes a casing **13** and production tubing **14** within which the desired oil or other petroleum product flows. The annular space between the casing and production tubing is filled with a completion liquid **16**. The viscosity of this completion liquid could be any viscosity within a wide range of possible viscosities. Its density also could be of any value within a wide range, and it may include corrosive liquid components like a high density salt such as a sodium, potassium and/or bromide compound.

In accordance with conventional practice, a packer **17** is provided to seal the borehole and the completion fluid from the desired petroleum product. The production tubing **14** extends through packer **17**. A plurality of remotely actuable wellbore tools may be carried by production tubing, on either side of packer **17**. This is possible since acoustic command signals may be transmitted through such sealing members as packer **17**, even though fluid will not pass through packer **17**.

A carrier **19** for the transducer of the invention is provided on the lower end of tubing **14**. As illustrated, a transition section **21** and one or more reflecting sections **22** (which will be discussed in more detail below) separate the carrier from the remainder of the production tubing. Such carrier includes slot **23** within which the communication transducer of the invention is held in a conventional manner, such as by strapping or the like. A data gathering instrument, a battery pack, and other components, also could be housed within slot **23**.

It is completion liquid **16** which acts as the transmission medium for acoustic waves provided by the transducer. Communication between the transducer and the annular space which confines such liquid is represented in **Figures 2** and **3** by port **24**. Data can be transmitted through the port **24** to the completion liquid and, hence, by the same in accordance with the invention. For example, a predetermined frequency band may be used for signaling by conventional coding and modulation techniques, binary data may be encoded into blocks, some error checking added, and the blocks transmitted serially by Frequency Shift Keying (FSK) or Phase Shift Keying (PSK) modulation. The receiver then will demodulate and check each block for errors.

The annular space at the carrier **19** is significantly smaller in cross-sectional area than that of the greater part of the well containing, for the most part, only production tubing **14**. This results in a corresponding mismatch of acoustic characteristic admittances. The purpose of transition section **21** is to minimize the reflections caused by the mismatch between the section having the transducer and the adjacent section. It is nominally one-quarter wavelength long at the desired center frequency and the sound speed in the fluid, and it is selected to have a diameter so that the annular area between it and the casing **13** is a geometric average of the product of the adjacent annular areas, (that is, the annular areas defined by the production tubing **14** and the carrier **19**). Further transition sections can be provided as necessary in the borehole to alleviate mismatches of acoustic admittances along the communication path.

Reflections from the packer (or the well bottom in other designs) are minimized by the presence of a multiple number of reflection sections or steps below the carrier, the first of which is indicated by reference numeral **22**. It provides a transition to the maximum possible annular area one-quarter wave-

length below the transducer communication port. It is followed by a quarter wavelength long tubular section **25** providing an annular area for liquid with the minimum cross-sectional area it otherwise would face. Each of the reflection sections or steps can be multiple number of quarter wavelengths long. The sections **19** and **21** should be an odd number of quarter wavelengths, whereas the section **25** should be odd or even (including zero), depending on whether or not the last step before the packer **17** has a large or small cross-section. It should be an even number (or zero) if the last step before the packer is from a large cross-section to a small cross-section.

While the first reflection step or section as described herein is the most effective, each additional one that can be added improves the degree and bandwidth of isolation. (Both the transition section **21**, the reflection section **22**, and the tubular section can be considered as parts of the combination making up the preferred transducer of the invention.)

A communication transducer for receiving the data is also provided at the location at which it is desired to have such data. In most arrangements this will be at the surface of the well, and the electronics for operation of the receiver and analysis of the communicated data also are at the surface or in some cases at another location. The receiving transducer **22** most desirably is a duplicate in principle of the transducer being described. (It is represented in **Figure 12** by box **25** at the surface of the well). The communication analysis electronics is represented by box **26**.

It will be recognized by those skilled in the art that the acoustic transducer arrangement of the invention is not limited necessarily to communication from downhole to the surface. Transducers can be located for communi-

cation between two different downhole locations. It is also important to note that the principle on which the transducer of the invention is based lends itself to two-way design: a single transducer can be designed to both convert an electrical communication signal to acoustic communication waves, and vice versa.

An implementation of the transducer of the invention is generally referred to by the reference numeral **26** in **Figures 4** through **7**. This specific design terminates at one end in a coupling or end plug **27** which is threaded into a bladder housing **28**. A bladder **29** for pressure expansion is provided in such housing. The housing **28** includes ports **31** for free flow into the same of the borehole completion liquid for interaction with the bladder. Such bladder communicates via a tube with a bore **32** extending through a coupler **33**. The bore **32** terminates in another tube **34** which extends into a resonator **36**. The length of the resonator is nominally $\lambda/4$ in the liquid within resonator **36**. The resonator is filled with a liquid which meets the criteria of having low density, viscosity, sound speed, water content, vapor pressure and thermal expansion coefficient. Since some of these requirements are mutually contradictory, a compromise must be made, based on the condition of the application and design constraints. The best choices have thus far been found among the 200 and 500 series Dow Corning silicone oils, refrigeration oils such as Capella B and lightweight hydrocarbons such as kerosene. The purpose of the bladder construction is to enable expansion of such liquid as necessary in view of the pressure and temperature of the borehole liquid at the downhole location of the transducer.

The transducer of the invention generates (or detects) acoustic wave energy by means of the interaction of a piston in the transducer housing with the borehole liquid. In this implementation, this is done by movement of a

piston **37** in a chamber **38** filled with the same liquid which fills resonator **36**. Thus, the interaction of piston **37** with the borehole liquid is indirect: the piston is not in direct contact with such borehole liquid. Acoustic waves are generated by expansion and contraction of a bellows type piston **37** in housing chamber **38**. One end of the bellows of the piston arrangement is permanently fastened around a small opening **39** of a horn structure **41** so that reciprocation of the other end of the bellows will result in the desired expansion and contraction of the same. Such expansion and contraction causes corresponding flexures of isolating diaphragms **42** in windows **43** to impart acoustic energy waves to the borehole liquid on the other side of such diaphragms. Resonator **36** provides a compliant back-load for this piston movement. It should be noted that the same liquid which fills the chamber of the resonator **36** and chamber **38** fills the various cavities of the piston driver to be discussed hereinafter, and the change in volumetric shape of chamber **38** caused by reciprocation of the piston takes place before pressure equalization can occur.

One way of looking at the resonator is that its chamber **36** acts, in effect, as a tuning pipe for returning in phase to piston **37** that acoustical energy which is not transmitted by the piston to the liquid in chamber **38** when such piston first moves. To this end, piston **37**, made up of a steel bellows **46** (**Figure 5**), is open at the surrounding horn opening **39**. The other end of the bellows is closed and has a driving shaft **47** secured thereto. The horn structure **41** communicates the resonator **36** with the piston, and such resonator aids in assuring that any acoustic energy generated by the piston that does not directly result in movement of isolating diaphragms **42** will reinforce the oscillatory motion of the piston. In essence, its intercepts that acoustic wave energy developed by the piston which does not directly result in radiation of acoustic waves and uses the same to enhance such radiation. It also acts to provide a compliant back-

load for the piston **37** as stated previously. It should be noted that the inner wall of the resonator could be tapered or otherwise contoured to modify the frequency response.

The driver for the piston will now be described. It includes the driving shaft **47** secured to the closed end of the bellows. Such shaft also is connected to an end cap **48** for a tubular bobbin **49** which carries two annular coils or windings **51** and **52** in corresponding, separate radial gaps **53** and **54** (**Figure 7**) of a closed loop magnetic circuit to be described. Such bobbin terminates at its other end in a second end cap **55** which is supported in position by a flat spring **56**. Spring **56** centers the end of the bobbin to which it is secured and constrains the same to limited movement in the direction of the longitudinal axis of the transducer, represented in **Figure 5** by line 57. A similar flat spring **58** is provided for the end cap **48**.

In keeping with the invention, a magnetic circuit having a plurality of gaps is defined within the housing. To this end, a cylindrical permanent magnet **60** is provided as part of the driver coaxial with the axis **57**. Such permanent magnet generates the magnetic flux needed for the magnetic circuit and terminates at each of its ends in a pole piece **61** and **62**, respectively, to concentrate the magnetic flux for flow through the pair of longitudinally spaced apart gaps **53** and **54** in the magnetic circuit. The magnetic circuit is completed by an annular magnetically passive member of magnetically permeable material **64**. As illustrated, such member includes a pair of inwardly directed annular flanges **66** and **67** (**Figure 7**) which terminate adjacent the windings **51** and **52** and define one side of the gaps **53** and **54**.

The magnetic circuit formed by this implementation is represented in **Figure 7** by closed loop magnetic flux lines **68**. As illustrated, such lines extend from the magnet **60**, through pole piece **61**, across gap **53** and coil **51**, through the return path provided by member **64**, through gap **54** and coil **52**, and through pole piece **62** to magnet **60**. With this arrangement, it will be seen that magnetic flux passes radially outward through gap 53 and radially inward through gap **54**. Coils **51** and **52** are connected in series opposition, so that current in the same provides additive force on the common bobbin. Thus, if the transducer is being used to transmit a communication, an electrical signal defining the same is passed through the coils **51** and **52** will cause corresponding movement of the bobbin **49** and, hence, the piston **37**. Such piston will interact through the windows **43** with the borehole liquid and impart the communicating acoustic energy thereto. Thus, the electrical power represented by the electrical signal is converted by the transducer to mechanical power, in the form of acoustic waves.

When the transducer receives a communication, the acoustic energy defining the same will flex the diaphragms **42** and correspondingly move the piston **37**. Movement of the bobbin and windings within the gaps **62** and **63** will generate a corresponding electrical signal in the coils **51** and **52** in view of the lines of magnetic flux which are cut by the same. In other words, the acoustic power is converted to electrical power.

In the implementation being described, it will be recognized that the permanent magnet **60** and its associated pole pieces **61** and **62** are generally cylindrical in shape with the axis **57** acting as an axis of a figure of revolution. The bobbin is a cylinder with the same axis, with the coils **51** and **52** being annular in shape. Return path member **64** also is annular and surrounds the magnet, etc. The magnet is held centrally by support rods **71** **(Figure 5)**

projecting inwardly from the return path member, through slots in bobbin **49**. The flat springs **56** and **58** correspondingly centralize the bobbin while allowing limited longitudinal motion of the same as aforesaid. Suitable electrical leads **72** for the windings and other electrical parts pass into the housing through potted feedthroughs **73**.

Figure 8A illustrates the implementation described above in schematic form. The resonator is represented at **36**, the horn structure at **41**, and the piston at **37**. The driver shaft of the piston is represented at **47**, whereas the driver mechanism itself is represented by box **74**. **Figure 8B** shows an alternate arrangement in which the driver is located within the resonator **76** and the piston **37** communicates directly with the borehole liquid which is allowed to flow in through windows **43**. The windows are open; they do not include a diaphragm or other structure which prevents the borehole liquid from entering the chamber **38**. It will be seen that in this arrangement the piston **37** and the horn structure **41** provide fluid-tight isolation between such chamber and the resonator **36**. It will be recognized, though, that it also could be designed for the resonator **36** to be flooded by the borehole liquid. It is desirable, if it is designed to be so flooded, that such resonator include a small bore filter or the like to exclude suspended particles. In any event, the driver itself should have its own inert fluid system because of close tolerances, and strong magnetic fields. The necessary use of certain materials in the same makes it prone to impairment by corrosion and contamination by particles, particularly magnetic ones.

Figures 9 through **13** are schematic illustrations representing various conceptual approaches and modifications for the transducer. **Figure 9** illustrates the modular design of the invention. In this connection, it should be noted that the invention is to be housed in a pipe of restricted diameter, but

length is not critical. The invention enables one to make the best possible use of cross-sectional area while multiple modules can be stacked to improve efficiency and power capability.

The bobbin, represented at **81** in **Figure 9**, carries three separate annular windings represented at **82-84**. A pair of magnetic circuits are provided, with permanent magnets represented at **86** and **87** with facing magnetic polarities and poles **88-90**. Return paths for both circuits are provided by an annular passive member **91**.

It will be seen that the two magnetic circuits of the **Figure 9** configuration have the central pole **89** and its associated gap in common. The result is a three-coil driver with a transmitting efficiency (available acoustic power output/electric power input) greater than twice that of a single driver, because of the absence of fringing flux at the joint ends. Obviously, the process of "stacking" two coil drivers as indicated by this arrangement with alternating magnet polarities can be continued as long as desired with the common bobbin being appropriately supported. In this schematic arrangement, the bobbin is connected to a piston **85** which includes a central domed part and bellows of the like sealing the same to an outer casing represented at **92**. This flexure seal support is preferred to sliding seals and bearings because the latter exhibit restriction that introduced distortion, particularly at the small displacements encountered when the transducer is used for receiving. Alternatively, a rigid piston can be sealed to the case with a bellows and a separate spring or spider used for centering. A spider represented at **94** can be used at the opposite end of the bobbin for centering the same. If such spider is metal, it can be insulated from the case and can be used for electrical connections to the moving windings, eliminating the flexible leads otherwise required.

In the alternative schematically illustrated in **Figure 10**, the magnet **86** is made annular and it surrounds a passive flux return path member **91** in its center. Since passive materials are available with saturation flux densities about twice the remanence of magnets, the design illustrated has the advantage of allowing a small diameter of the poles represented at **88** and **90** to reduce coil resistance and increase efficiency. The passive flux return path member **91** could be replaced by another permanent magnet. A two- magnet design, of course, could permit a reduction in length of the driver.

Figure 11 schematically illustrates another magnetic structure for the driver. It includes a pair of oppositely radially polarized annular magnets **95** and **96**. As illustrated, such magnets define the outer edges of the gaps. In this arrangement, an annular passive magnetic member **97** is provided, as well as a central return path member **91**. While this arrangement has the advantage of reduced length due to a reduction of flux leakage at the gaps and low external flux leakage, it has the disadvantage of more difficult magnet fabrication and lower flux density in such gaps.

Conical interfaces can be provided between the magnets and pole pieces. Thus, the mating junctions can be made oblique to the long axis of the transducer. This construction maximizes the magnetic volume and its accompanying available energy while avoiding localized flux densities that could exceed a magnet remanence. It should be noted that any of the junctions, magnet-to-magnet, pole piece-to-pole piece and of course magnet-to-pole piece can be made conical. **Figure 12** illustrates one arrangement for this feature. It should be noted that in this arrangement the magnets may includes pieces **98** at the ends of the passive flux return member **91** as illustrated.

Figure 13 schematically illustrates a particular combination of the options set forth in **Figures 9** through **12** which could be considered a preferred embodiment for certain applications. It includes a pair of pole pieces **101**, and **102** which mate conically with radial magnets **103**, **104** and **105**. The two magnetic circuits which are formed include passive return path members **106** and **107** terminating at the gaps in additional magnets 108 and **110**.

<u>THE COMMUNICATION SYSTEM:</u> The communication system of the present invention will be described with reference to **Figures 14** through **21**.

With reference to **Figure 14**, a borehole **1100** is illustrated extending through the earth **1102**. Borehole **1100** is shown as a petroleum product completion hole for illustrative purposes. It includes a casing **1104** and production tubing **1106** within which the desired oil or other petroleum product flows. The annular space between the casing and production tubing is filled with borehole completion liquid **1108**. The properties of a completion fluid vary significantly from well to well and over time in any specific well. It typically will include suspended particles or partially be a gel. It is non-Newtonian and may include non-linear elastic properties. Its viscosity could be any viscosity within a wide range of possible viscosities. Its density also could be of any value within a wide range, and it may include corrosive solid or liquid components like a high density salt such as a sodium, calcium, potassium and/or a bromide compound.

A carrier **1112** for a downhole acoustic transceiver (DAT) and its associated transducer is provided on the lower end of the tubing **1106**. As illustrated, a transition section **1114** and one or more reflecting sections **1116** are included and separate carrier **1112** from the remainder of production tubing

1106. Carrier **1112** includes numerous slots in accordance with conventional practice, within one of which, slot **1118**, the downhole acoustic transducer (DAT) of the invention is held by strapping or the like. One or more data gathering instruments or a battery pack also could be housed within slot **1118**. It will be appreciated that a plurality of slots could be provided to serve the function of slot **1118**. The annular space between the casing and the production tubing is sealed adjacent the bottom of the borehole by packer **1110**. The production tubing **1106** extends through the packer and **1110** a safety valve, data gathering instrumentation, and other wellbore tools, may be included.

It is the completion liquid **1108** which acts as the transmission medium for acoustic waves provided by the transducer. Communication between the transducer and the annular space which confines such liquid is represented in **Figure 17** by port **1120**. Data can be transmitted through the port **1120** to the completion liquid via acoustic signals. Such communication does not rely on flow of the completion liquid.

A surface acoustic transceiver (SAT) **1126** is provided at the surface, communicating with the completion liquid in any convenient fashion, but preferably utilizing a transducer in accordance with the present invention. The surface configuration of the production well is diagrammatically represented and includes an end cap on casing **1124**. The production tubing **1106** extends through a seal represented at **1122** to a production flow line **1123**. A flow line for the completion fluid **1124** is also illustrated, which extends to a conventional circulation system.

In its simplest form, the arrangement converts information laden data into an acoustic signal which is coupled to the borehole liquid at one

location in the borehole. The acoustic signal is received at a second location in the borehole where the data is recovered. Alternatively, communication occurs between both locations in a bidirectional fashion. And as a further alternative, communication can occur between multiple locations within the borehole such that a network of communication transceivers are arrayed along the borehole. Moreover, communication could be through the fluid in the production tubing through the product which is being produced. Many of the aspects of the specific communication method described are applicable as mentioned previously to communication through other transmission medium provided in a borehole, such as in the walls of the tubing **1106**, through air gaps contained in a third column, or through wellbore tools such as packer **1101**.

Referring to **Figure 15**, the transducer **1200** at the downhole location is coupled to a downhole acoustic transceiver (DAT) **1202** for acoustically transmitting data collected from the DAT's associated sensors **1201**. The DAT **1202** is capable of both modulating an electrical signal used to stimulate the transducer **1200** for transmission, and of demodulating signals received by the transducer **1200** from the surface acoustic transceiver (SAT) **1204**. In other words, the DAT **1202** both receives and transmits information. Similarly, the SAT **1204** both receives and transmits information. The communication is directly between the DAT **1202** and the SAT **1204**. Alternatively, intermediary transceivers could be positioned within the borehole to accomplish data relay. Additional DATs could also be provided to transmit independently gathered data from their own sensors to the SAT or to another DAT.

More specifically, the bi-directional communication system of the invention establishes accurate data transfer by conducting a series of steps designed to characterize the borehole communication channel **1206**, choose the

best center frequency based upon the channel characterization, synchronize the SAT **1204** with the DAT **1202** , and, finally, bi-directionally transfer data. This complex process is undertaken because the channel **1206** through which the acoustic signal must propagate is dynamic, and thus time variant. Furthermore, the channel is forced to be reciprocal: the transducers are electrically loaded as necessary to provide for reciprocity.

In an effort to mitigate the effects of the channel interference upon the information throughput, the inventive communication system characterizes the channel in the uphole direction **1210**. To do so, the DAT **1202** sends a repetitive chirp signal which the SAT **1204**, in conjunction with its computer **1128**, analyzes to determine the best center frequency for the system to use for effective communication in the uphole direction. It will be recognized that the downhole direction **1208** could be characterized rather than, or in addition to, characterization for uphole communication.

Each transceiver could be designed to characterize the channel in the incoming communication direction: the SAT **1204** could analyze the channel for uphole communication **1210** and the DAT **1202** could analyze for downhole communication **1208**, and then command the corresponding transmitting system to use the best center frequency for the direction characterized by it.

In addition to choosing a proper channel for transmission, system timing synchronization is important to any coherent communication system. To accomplish the channel characterization and timing synchronization processes together, the DAT begins transmitting repetitive chirp sequences after a programmed time delay selected to be longer than the expected lowering time.

Figures 18A-18C depict the signalling structure for the chirp sequences. In a preferred implementation, a single chirp block is one hundred milliseconds in duration and contains three cycles of one hundred fifty (150) Hertz signal, four cycles of two hundred (200) Hertz signal, five cycles of two hundred and fifty (250) Hertz signal, six cycles of three hundred (300) Hertz signal, and seven cycles of three hundred and fifty (350) Hertz cycles. The chirp signal structure is depicted in **Figure 18A**. Thus, the entire bandwidth of the desired acoustic channel, one hundred and fifty to three hundred and fifty (150-350) Hertz, is chirped by each block.

As depicted in **Figure 18B**, the chirp block is repeated with a time delay between each block. As shown in **Figure 18C**, this sequence is repeated three times at two minute intervals. The first two sequences are transmitted sequentially without any delay between them, then a delay is created before a third sequence is transmitted. During most of the remainder of the interval, the DAT **1202** waits for a command (or default tone) from the SAT **1204**. The specific sequence of chirp signals should not be construed as limiting the invention: variations on the basic scheme, including but not limited to different chirp frequencies, chirp durations, chirp pulse separations, etc., are foreseeable. It is also contemplated that PN sequences, an impulse, or any variable signal which occupies the desired spectrum could be used.

As shown in **Figure 20**, the SAT **1204** of the preferred embodiment of the invention uses two microprocessors **1616**, **1626** to effectively control the SAT functions. The host computer **1128** controls all of the activities of the SAT **1204** and is connected thereto via one of two serial channels of a Model 68000 microprocessor **1626** in the SAT **1204**. The 68000 microprocessor accomplishes the bulk of the signal processing functions that are discussed below. The second

serial channel of the 68000 microprocessor is connected to a 68HC11 processor **1616** that controls the signal digitization with Analog-to-Digital Converter **1614**, the retrieval of received data, and the sending of tones and commands to the DAT. The chirp sequence is received from the DAT by the transducer **1205** and converted into an electrical signal from an acoustic signal. The electrical signal is coupled to the receiver through transformer **1600** which provides impedance matching. Amplifier **1602** increases the signal level, and the bandpass filter **1604** limits the noise bandwidth to three hundred and fifty (350) Hertz centered at two hundred and fifty (250) Hertz and also functions as an anti-alias filter.

Referring to **Figure 19**, the DAT **1202** has a single 68HC11 microprocessor **1512** that controls all transceiver functions, the data logging activities, logged data retrieval and transmission, and power control. For simplicity, all communications are interrupt-driven. In addition, data from the sensors are buffered, as represented by block **1510**, as it arrives. Moreover, the commands are processed in the background by algorithms **1700** which are specifically designed for that purpose.

The DAT **1202** and SAT **1204** include, though not explicitly shown in the block diagrams of **Figures 19** and **20**, all of the requisite microprocessor support circuitry. These circuits, including RAM, ROM, clocks, and buffers, are well known in the art of microprocessor circuit design.

In order to characterize the communication channel for upward signals, generation of the chirp sequence is accomplished by a digital signal generator controlled by the DAT microprocessor **1512**. Typically, the chirp block is generated by a digital counter having its output controlled by a microprocessor to generate the complete chirp sequence. Circuits of this nature are widely used

for variable frequency clock signal generation. The chirp generation circuitry is depicted as block **1500** in **Figure 19**, a block diagram of the DAT **1202**. Note that the digital output is used to generate a three level signal at **1502** for driving the transducer **1200**. It is chosen for this application to maintain most of the signal energy in the acoustic spectrum of interest: one hundred and fifty Hertz to three hundred and fifty Hertz. The primary purpose of the third state is to terminate operation of the transmitting portion of a transceiver during its receiving mode: it is, in essence, a short circuit.

Figure 16 and **Figure 17** are flow charts of the DAT and SAT operations, respectively. The chirp sequences are generated during step **1300**. Prior to the first chirp pulse being transmitted after the selected time delay, the surface transceiver awaits the arrival of the chirp sequences in accordance with step **1400** in **Figure 17**. The DAT is programmed to transmit a burst of chirps every two minutes until it receives two tones: fc and fc+1. Initial synchronization starts after a "characterize channel" command is issued at the host computer. Upon receiving the "characterize channel" command, the SAT starts digitizing transducer data. The raw transducer data is conditioned through a chain of amplifiers, anti-aliasing filters, and level translators, before being digitized. One second data block (1024 samples) is stored in a buffer and pipelined for subsequent processing.

The functions of the chirp correlator are threefold. First, it synchronizes the SAT TX/RX clock to that of the DAT. Second, it calculates a clock error between the SAT and DAT timebases, and corrects the SAT clock to match that of the DAT. Third, it calculates a one Hertz resolution channel spectrum.

The correlator performs a FFT ("Fast Fourier Transform") on a .25 second data block, and retains FFT signal bins between one hundred and forty Hertz to three hundred and sixty Hertz. The complex valued signal is added coherently to a running sum buffer containing the FFT sum over the last six seconds (24 FFTs). In addition, the FFT bins are incoherently added as follows: magnitude squared, to a running sum over the last 6 seconds. An estimate of the signal to noise ratio (SNR) in each frequency bin is made by a ratio of the coherent bin power to an estimated noise bin power. The noise power in each frequency bin is computed as the difference of the incoherent bin power minus the coherent bin power. After the SNR in each frequency bin is computed, an "SNR sum" is computed by summing the individual bin SNRs. The SNR sum is added to the past twelve and eighteen second SNR sums to form a correlator output every .25 seconds and is stored in an eighteen second circular buffer. In addition, a phase angle in each frequency bin is calculated from the six second buffer sum and placed into an eighteen second circular phase angle buffer for later use in clock error calculations.

After the chirp correlator has run the required number of seconds of data through and stored the results in the correlator buffer, the correlator peak is found by comparing each correlator point to a noise floor plus a preset threshold. After detecting a chirp, all subsequent SAT activities are synchronized to the time at which the peak was found.

After the chirp presence is detected, an estimate of sampling clock difference between the SAT and DAT is computed using the eighteen second circular phase angle buffer. Phase angle difference (■ϕ) over a six second time interval is computed for each frequency bin. A first clock error estimation is computed by averaging the weighted phase angle difference over all the

frequency bins. Second and third clock error estimations are similarly calculated respectively over twelve and one hundred and eighty-five second time intervals. A weighted average of three clock error estimates gives the final clock error value. At this point in time, the SAT clock is adjusted and further clock refinement is made at the next two minute chirp interval in similar fashion.

After the second clock refinement, the SAT waits for the next set of chirps at the two minute interval and averages twenty-four .25 second chirps over the next six seconds. The averaged data is zero padded and then FFT is computed to provide one Hertz resolution channel spectrum. The surface system looks for a suitable transmission frequency in the one hundred and fifty Hertz to three hundred and fifty Hertz. Generally, a frequency band having a good signal to noise ratio and bandwidths of approximately two Hertz to forty Hertz is acceptable. A width of the available channel defines the acceptable baud rate.

The second phase of the initial communication process involves establishing an operational communication link between the SAT **1204** and the DAT **1202**. Toward this end, two tones, each having a duration of two seconds, are sequentially sent to the DAT **1202**. One tone is at the chosen center frequency and the other is offset from the center frequency by exactly one hertz. This step in the operation of the SAT **1204** is represented by block **1406** in **Figure 17**.

The DAT is always looking for these two tones: fc and fc+1, after it has stopped chirping. Before looking for these tones, it acquires a one second block of data at a time when it is known that there is no signal. The noise collection generally starts six seconds after the chirp ends to provide time for

echoes to die down, and continues for the next thirty seconds. During the thirty second noise collection interval, a power spectrum of one second data block is added to a three second long running average power spectrum as often as the processor can compute the 1024 point (one second) power spectrum.

The DAT starts looking for the two tones approximately thirty-fix seconds after the end of the chirp and continues looking for them for a period of four seconds (tone duration) plus twice the maximum propagation time. The DAT again calculates the power spectrum of one second blocks as fast as it can, and computes signal to noise ratios for each one Hertz wide frequency bins. All the frequency components which are a preset threshold above a noise floor are possible candidates. If a frequency is a candidate in two successive blocks, then the tone is detected at its frequency. If the tones are not recognized, the DAT continues to chirp at the next two minute interval. When the tones are received and properly recognized by the DAT, the DAT transmits the same two tones back to the SAT followed by an ACK at the selected carrier frequency fc.

A by-product of the process of recognizing the tones is that it enables the DAT to synchronize its internal clock to the surface transceiver's clock. Using the SAT clock as the reference clock, the tone pair can be said to begin at time t=0. Also assume that the clock in the surface transceiver produces a tick every second as depicted in **Figure 21**. This alignment is desirable to enable each clock to tick off seconds synchronously and maintain coherency for accurately demodulating the data. However, the DAT is not sure when it will receive the pair, so it conducts an FFT every second relative to its own internal clock which can be assumed not to be aligned with the surface clock. When the four seconds of tone pair arrive, they will more than likely cover only three one second FFT interval fully and only two of those will contain a single frequency.

Figure 21 is helpful in visualizing this arrangement. Note that the FFT periods having a full one second of tone signal located within it will produce a maximum FFT peak.

Once received, an FFT of each two second tone produces both amplitude and phase components of the signal. When the phase component of the first signal is compared with the phase component of the second signal, the one second ticks of the downhole clock can be aligned with the surface clock. For example, a two hundred Hertz tone followed immediately by a two hundred and one Hertz tone is sent from the transceiver at time t=0. Assume that the propagation delay is one and one-half seconds and the difference between the one second ticking of the clocks is .25 seconds. This interval is equivalent to three hundred and fifty cycles of two hundred Hertz Hz signal and 351.75 cycles of two hundred and one Hertz tone. Since an even number of cycles has passed for the first tone, its phase will be zero after the FFT is accomplished. However, the phase of the second tone will be two hundred and seventy degrees from that of the first tone. Consequently, the difference between the phases of each tone is two hundred and seventy degrees which corresponds to an offset of .75 seconds between the clocks. If the DAT adjusts its clock by .75 seconds, the one second ticks will be aligned. In general, the phase difference defines the time offset. This offset is corrected in this implementation. The timing correction process is represented by step **1308** in **Figure 16** and is accomplished by the software in the DAT, as represented by the software blocks in the DAT block diagram.

It should be noted that the tones are generated in both the DAT and SAT in the same manner as the chirp signals were generated in the DAT. As described previously, in the preferred embodiment of the invention, a

microprocessor controlled digital signal generator **1500**, **1628** creates a pulse stream of any frequency in the band of interest. Subsequent to generation, the tones are converted into a three level signal at **1502**, **1630** for transmission by the transducer **1200, 1205** through the acoustic channel.

After tone recognition and retransmission, the DAT adjusts its clock, then switches to the Minimum Shift Keying (MSK) modulation receiving mode. (Any modulation technique can be used, although it is preferred that MSK be used for the invention for the reasons discussed below.) Additionally, if the tones are properly recognized by the SAT as being identical to the tones which were sent, it transmits a MSK modulated command instructing the DAT as to what baud rate the downhole unit should use to send its data to achieve the best bit energy to noise ratio at the SAT. The DAT is capable of selecting 2 to 40 baud in 2 baud increments for its transmissions. The communication link in the downhole direction is maintained at a two baud rate, which rate could be increased if desired. Additionally, the initial message instructs the downhole transceiver of the proper transmission center frequency to use for its transmissions.

If, however, the tones are not received by the downhole transceiver, it will revert to chirping again. SAT did not receive the ACK followed by tones since DAT did not transmit them. In this case the operator can either try sending tones however many times he wants to or try recharacterizing channel which will essentially resynchronize the system. In the case of sending two tones again, SAT will wait until the next tone transmit time during which the DAT would be listening for the tones.

If the downhole transceiver receives the tones and retransmits them, but the SAT does not detect them, the DAT will have switched to this MSK mode to await the MSK commands, and it will not be possible for it to detect the tones which are transmitted a second time, if the operator decides to retransmit rather than to recharacterize. Therefore, the DAT will wait a set duration. If the MSK command is not received during that period, it will switch back to the synchronization mode and begin sending chirp sequences every two minutes. This same recovery procedure will be implemented if the established communication link should subsequently deteriorate.

As previously mentioned, the commands are modulated in an MSK format. MSK is a form of modulation which, in effect, is binary frequency shift keying (FSK) having continuous phase during the frequency shift occurrences. As mentioned above, the choice of MSK modulation for use in the preferred embodiment of the invention should not be construed as limiting the invention. For example, binary phase shift keying (BPSK), quadrature phase shift keying (QPSK), or any one of the many forms of modulation could be used in this acoustic communication system.

In the preferred embodiment, the commands are generated by the host computer **1128** as digital words. Each command is encoded by a cyclical redundancy code (CRC) to provide error detection and correction capability. Thus, the basic command is expanded by the addition of the error detection bits. The encoded command is sent to the MSK modulator portion of the 68HC11 microprocessor's software. The encoded command bits control the same digital frequency generator **1628** used for tone generation to generate the MSK modulated signals. In general, each encoded command bit is mapped, in this implementation, onto a first frequency and the next bit is mapped to a second

frequency. For example, if the channel center frequency is two hundred and thirteen Hertz, the data may be mapped onto frequencies two hundred and eighteen Hertz, representing a "1", and two hundred and eight Hertz, representing a "0". The transitions between the two frequencies are phase continuous.

Upon receiving the baud rate command, the DAT will send an acknowledgement to the SAT. If an acknowledgement is not received by the SAT, it will resend the baud rate command if the operator decides to retry. If an operator wishes, the SAT can be commanded to resynchronize and recharacterize with the next set of chirps.

A command is sent by the SAT to instruct the DAT to begin sending data. If an acknowledgement is not received, the operator can resend the command if desired. The SAT resets and awaits the chirp signals if the operator decides to resynchronize. However, if an acknowledgement is sent from the DAT, data are automatically transmitted by the DAT directly following the acknowledgement. Data are received by the SAT at the step represented at **1434**.

Nominally, the downhole transceiver will transmit for four minutes and then stop and listen for the next command from the SAT. Once the command is received, the DAT will transmit another 4 minute block of data. Alternatively, the transmission period can be programmed via the commands from the surface unit.

It is foreseeable that the data may be collected from the sensors **1201** in the downhole package faster than they can be sent to the surface.

Therefore, the DAT may include buffer memory **1510** to store the incoming data from the sensors **1201** for a short duration prior to transmitting it to the surface.

The data is encoded and MSK modulated in the DAT in the same manner that the commands were encoded and modulated in the SAT, except the DAT may use a higher data rate: two to forty baud, for transmission. The CRC encoding is accomplished by the microprocessor **1512** prior to modulating the signals using the same circuitry **1500** used to generate the chirp and tone bursts. The MSK modulated signals are converted to tri-state signals **1502** and transmitted via the transducer **1200**.

In both the DAT and the SAT, the digitized data are processed by a quadrature demodulator. The sine and cosine waveforms generated by oscillators **1635**, **1636** are centered at the center frequency originally chosen during the synchronization mode. Initially, the phase of each oscillator is synchronized to the phase of the incoming signal via carrier transmission. During data recovery, the phase of the incoming signal is tracked to maintain synchrony via a phase tracking system such as a Costas loop or a squaring loop.

The I and Q channels each use finite impulse response (FIR) low pass filters **1638** having a response which approximately matches the bit rate. For the DAT, the filter response is fixed since the system always receives thirty-two bit commands. Conversely, the SAT receives data at varying baud rates; therefore, the filters must be adaptive to match the current baud rate. The filter response is changed each time the baud rate is changed.

Subsequently, the I/Q sampling algorithm **1640** optimally samples both the I and Q channels at the apex of the demodulated bit. However, optimal

sampling requires an active clock tracking circuit, which is provided. Any of the many traditional clock tracking circuits would suffice: a tau-dither clock tracking loop, a delay-lock tracking loop, or the like. The output of the I/Q sampler is a stream of digital bits representative of the information.

The information which was originally transmitted is recovered by decoding the bit stream. To this end, a decoder **1642** which matches the encoder used in the transmitter process: a CRC decoder, decodes and detects errors in the received data. The decoded information carrying data is used to instruct the DAT to accomplish a new task, to instruct the SAT to receive a different baud rate, or is stored as received sensor data by the SAT's host computer.

The transducer, as the interface between the electronics and the transmission medium, is an important segment of the current invention; therefore, it was discussed separately above. An identical transducer is used at each end of the communications link in this implementation, although it is recognized that in many situations it may be desirable to use differently configured transducers at the opposite ends of the communication link. In this implementation, the system is assured when analyzing the channel that the link transmitter and receiver are reciprocal and only the channel anomalies are analyzed. Moreover, to meet the environmental demands of the borehole, the transducers must be extremely rugged or reliability is compromised.

3. ACOUSTIC TONE GENERATOR AND RECEIVER - SOFTWARE VERSION.

In accordance with one embodiment of the present invention, a predominantly software version is utilized to send and decode acoustic coded

messages which are utilized to individually and selectively actuate particular wellbore tools carried within a completion and/or drill stem test string.

Utilizing the acoustic transducer and communication system (described and depicted in connection with **Figures 2** through **21**), a series of coded acoustic messages are generated at an uphole or surface location for transmission to a downhole location, and reception and decoding by a controller associated with a transceiver located therein. **Figure 22** is a graphical depiction of the types of signals communicated within the wellbore and the relative timing of the signals. Since the quality of the communication channel is unknown, the series of signals depicted in **Figure 22** may be repeated for different frequencies until communication with the wellbore receiver is obtained and actuation of a particular wellbore tool is accomplished. In the preferred embodiment of the present invention, the wake-up tone **5001** is stepped through a predetermined number of different frequencies until it is determined that actuation of the particular wellbore tool has occurred. In the preferred embodiment of the present invention, on the first pass, the wake-up tone utilized is 22 Hertz. If no actuation occurs, the process is repeated a second time at 44 Hertz; still, if no actuation is detected, the entire process is repeated with a wake-up tone at 88 Hertz.

As is shown in **Figure 22**, the wake-up tone **5001** is transmitted within the wellbore within time interval **5015**, which is preferably a 30-second interval. A pause is provided during time interval **5017**, having a 3-second duration. Then, a frequency select tone **5003** is communicated within the wellbore during time interval **5019**, which is also preferably a 3-second time interval. The frequency select tone is, as discussed above in connection with the basic communication technology, a chirp including a variety of predetermined frequencies which are utilized to determine the carrier or communication frequencies for subsequent

communications. In frequency shift keying modulation, the frequency select tone **5003** is utilized to select a first frequency (F1) and a second frequency (F2) which are representative of binary 0 and binary 1 in a frequency shift keying scheme. After the frequency select tone **5003** is transmitted, a pause is provided during time interval **5021** which has a duration of three seconds. During this interval, a downhole processor is utilized to analyze the chirp and to determine the optimum frequency segments which may be utilized for the frequency shift keying. Next, during time interval **5023** (which is preferably 4.5 seconds) synchronizing bits **5007** are communicated between the downhole and surface equipment in order to synchronize the downhole and surface systems. A pause is provided during time interval **5025** (which is preferably 3 seconds). Then, during time interval **5027** (which is preferably 13.5 seconds), a nine-bit address command **5009** is communicated. The nine-bit address command **5009** is identified with a particular one of the plurality of wellbore tools maintained in the subsurface location. After the nine-bit address command **5009** is communicated, a pause is provided during time interval **5029** (which is preferably 10 seconds). Next, during time interval **5031** (which is preferably 13.5 seconds) a nine-bit fire command **5011** is communicated which initiates actuation of the particular wellbore tool. If the fire command **5011** is recognized, a fire condition ensues during time interval **5033** (which is preferably about 20 seconds). During that time interval, a fire pulse **5013** is communicated to the end device in order to actuate it.

Figure 23 is a flowchart representation of the technique utilized in the software version of the present invention in order to actuate particular wellbore tools. The process begins at software block **5035**, and continues at software block **5037**, wherein the software is utilized to determine whether a wake-up tone has been received; if not, control returns to software **5035**; if a wake-up tone has been received, control passes to software block **5039**, wherein the frequency

select procedure is implemented. Then, in accordance with software block **5041**, the synchronized procedure is implemented. Next, in accordance with software block **5043**, the controller and associated software is utilized to determine whether a particular tool has been addressed; if not, the controller continues monitoring for the 13.5 second interval of time interval **5027** of **Figure 22**. If no tool is addressed during that time interval, the process is aborted. However, if a particular tool has been addressed, control passes to software block **5045**, wherein it is determined whether, within the time interval **5031** of **Figure 22**, a fire command has been received; if no fire command is received during this 13.5 second time interval, control passes to software block **5049**, wherein the controller and associated software is utilized to determine whether, within the time interval **5031** of **Figure 22**, a fire command has been received; if not, control passes to software block **5049**, wherein the process is aborted; if so, control passes to software block **5047**, which is a fire pulse procedure which initiates a fire pulse to actuate the particular end device. After the fire pulse procedure **5047** is completed, control passes to software block **5049** wherein the process is terminated.

4. THE ACOUSTIC TONE GENERATOR AND RECEIVER - HARDWARE VERSION.

An alternative hardware embodiment will now be discussed.

The acoustic tone actuator (ATA) includes an acoustic tone generator **4100** which is located preferably at a surface location and which is in communication with an acoustic communication pathway within a wellbore. A portion of the acoustic tone generator **4100** is depicted in block diagram form in **Figure 24**. The acoustic tone actuator also includes an acoustic tone receiver

4200 which is preferably located in a subsurface portion of a wellbore, and which is in communication with a fluid column which extends between the acoustic tone generator **4100** and the acoustic tone receiver **4200**. The acoustic tone receiver **4200** is depicted in block diagram and electrical schematic form in **Figures 25** through 28. **Figures 29A** through 29G depict timing charts for various components and portions of the acoustic tone generator **4100** of **Figure 24** and the acoustic tone receiver **4200** of **Figures 25** through **28**.

Figure 30 graphically depicts the intended and preferred use of the acoustic tone actuator. As is shown, wellbore **301** includes casing **303** which is fixed in position relative to formation **305** and which serves to prevent collapse or degradation of wellbore **301**. A tubular string **307** is located within the central bore of casing **303** and includes upper perforating gun **309**, middle perforating gun **311**, and lower perforating gun **313**. The acoustic tone actuator may be utilized to individually and selectively actuate each of the perforating guns **309**, **311**, **313**. Preferably, each of perforating guns **309**, **311**, **313** is hard-wired configured to be responsive to a particular one of a plurality of discreet available acoustic tone coded messages which are transmitted from acoustic tone generator **4100** of **Figure 24** and which are received by acoustic tone receiver **4200** of **Figures 25** through 28. When a particular one of perforating guns **309**, **311**, **313** is actuated, an electrical current is supplied to an electrically-actuable explosive charge which causes an explosion which propels piercing bodies outward from tubing string **307** toward casing **303**, perforating casing **303**, and thus allowing the communication of gases and fluids between formation **305** and the central bore of casing **303**.

The preferred acoustic tone generator **4100** will now be described with reference to **Figure 24**, and the timing chart of **Figures 29A** through **29G**. With

reference now to **Figure 24**, acoustic tone generator **4100** includes clock **4101** which generates a uniform timing pulse, such as that depicted in the timing chart of **Figure 29A**. A pulse of a particular duration is automatically generated by clock **101** at a clock frequency w_c. Operation of acoustic tone generator **4100** is initiated by actuation of start button **4103**. The output of clock **4101** and the output of start button **4103** are provided to AND-gate **4105**. When both of the inputs to AND-gate **105** are high, the output of AND-gate **105** will be high. All other input combinations will result in an output of a binary zero from AND-gate **105**. The reset line of start button **103** may be utilized to switch back to an off-condition. The output of AND-gate **105** is supplied to inverter **107**, inverter **109**, and modulating AND-gate **115**. The output of inverter **107** is supplied to counter **111**. Counter **111** operates to count eight consecutive pulses from clock **103**, and then to provide a reset signal to the reset line of start button **103**. The output of inverter **109** is supplied to universal asynchronous receiver/transmitter (UART) **113** which is adapted to receive an eight-bit binary parallel input, and to provide an eight-bit binary serial output. The input of bits 1-8 is provided by any conventional means such as an eight-pin dual-in-line-package switch, also known as a "DIP switch". In alternative embodiments, the eight-bit parallel input may be provided by any other conventional means. The serial output of UART **113** is provided as an input to modulating AND-gate **115**. The output of AND-gate **105** is also supplied as an input to modulating AND-gate **115**. The output of modulating AND-gate **115** is the bit-by-bit binary product of the clock signal w_c and the eight-bit serial binary output of UART **113** w_d. The output of modulating AND-gate **115** is supplied as a control signal to an electrically-actuated pressure pulse generator **175**, such as has been described above. Therefore, the eight bit serial data is supplied in the form of acoustic pulses or tones to a predefined acoustic communication path which extends from the acoustic tone generator

100 of **Figure 6** to the acoustic tone receiver **200** of **Figure 7**, where it is detected.

With reference now to **Figures 29A** through **29G**, the eight-bit serial binary data will be discussed and described in detail. **Figure 29A** depicts eight consecutive pulses from clock **4103**. Bit number **1** defines a start pulse which alerts the remotely located receiver that binary data follows. Bit number **2** represents a synchronization bit which allows the remotely located acoustic pulse receiver **4200** to determine if it is in synchronized operation with the acoustic tone generator **4100**. Bits **3**, **4**, **5**, and **6** represent a four-bit binary word which is determined by the serial input to UART **4113** of **Figure 24**. Bit number **7** represents a parity bit which is either high or low depending upon the content of bits **3** through **6** in a particular parity scheme or protocol. The parity bit is useful in determining whether a correct signal has been received by acoustic tone receiver **4200**. **Figures 29B** through **29E** represent three different binary values for bits **3** through **6**. The timing chart of **Figure 29B** represents a binary value of zero for bits **3** through **6**. The timing chart of **Figure 29C** represents a binary value of one for bits **3** through **6**. The timing chart of **Figure 29D** represents a binary value of two for bits **3** through **6**. The timing chart of **Figure 29E** represents a binary value of three for bits **3** through **6**. Since four binary bits are available to represent coded messages, a total of sixteen possible different codes may be provided (with binary values of 0 through 15). The timing chart of **Figure 29F** represents the bit-by-bit product of the timing pulse and a binary value of zero for bits **3** through **6**. In contrast, timing chart of **Figure 29G** represents the bit-by-bit product of the timing pulse and a binary value of one for bits **3** through **6**. Since the binary value of bits **3** through **6** of timing chart **29F** is zero (and thus even) the value of parity bit **7** is a binary zero. In contrast, since

the binary value of bits **3** through **6** of timing chart **29G** is one (and thus odd) the binary value of parity bit **7** is one.

Figure 25 is a block diagram and electrical schematic depiction of acoustic tone receiver **4200**. Reception circuit **4201** includes transducers and at least one stage of signal amplification. Synchronizing clock **4203** is provided to provide a clock signal w_c with the same pulse frequency of clock **4101** of acoustic tone generator **4100** of **Figure 24**. Additionally, synchronizing clock **4203** provides a synchronizing pulse like the synchronizing pulses of bits **2** and **8** of **Figures 8A** through 8G. The output of synchronizing clock **4203** is provided to counter **4205** which provides a binary one for every eight clock pulses counted. The output of counter **4205** is supplied as one input to AND-gate **4207**. The other two inputs to AND-gate **4207** will be supplied from two particular bits of data present in shift register **4209**. Shift register **4209** receives as an input the acoustic pulses detected by receiver circuit **4201**. Namely, it receives the bit-by-bit product of w_c and w_d, as a serial input. Additionally, shift register **4209** is clocked by the clock output of synchronizing clock **4203**. Thus, the acoustic pulses detected by receiving circuit **4201** are clocked into shift register **4209** one-by-one at a rate established by synchronizing clock **4203**. The parity bit and a synchronizing bit are supplied from shift register **4209** as the other two inputs to AND-gate 4207. When all the input lines to AND-gate **4207** are high, AND-gate provides a binary strobe which actuates shift register **4209**, causing it to pass the eight-bit serial binary data from shift register **4209** to demodulator **4211**. Preferably, demodulator **4211** receives a multi-bit parallel input, and maps that to a particular one of sixteen available output lines. Demodulator **4211** is depicted in **Figure 29B**. As is shown, sixteen available output pins are provided. The input of a particular binary (or hexadecimal) input will produce a high voltage at a particular pin associated with the particular binary or hexadecimal value. For

example, demodulator **4211** may supply a high voltage at pin **9** if binary **9** is received as an input. In that particular case, jumpers **4217, 4219** may be utilized to allow the application of the high voltage from pin **9** to the base of switching transistor **4221**. In this configuration, when pin **9** goes high, switching transistor **4221** is switched from a non-conducting condition to a conducting condition, allowing current to flow from pin **4223** (which is at +V volts) through switching transistor **4221** and perforation actuator **4225**. Preferably, the perforating guns include a thermally-actuated power charge, and element **4225** comprises a heating wire extending through the power charge.

With reference now to **Figure 29A**, simultaneous with the generation of a voltage of a particular pin of demodulator **4211**, the voltage from that particular pin is applied as an input to NOR-gate **4213**. Additionally, the synchronizing pulse train generated by synchronizing clock **4203** is supplied as an input to NOR-gate **4213**. The output of NOR-gate **4213** is a master-clear line which is utilized to reset demodulator **4211**; synchronizing clock **4213**, counter **4205**, and reception circuit **4201**. This places the circuit components in a condition for receiving an additional acoustic pulse train from acoustic tone generator **4100** of **Figure 24.**

Figure 27 is a block diagram representation of one preferred embodiment of the acoustic tone receiver **4200**. As is shown, hydrophone **505** is utilized to detect the acoustic signals and direct electrical signals corresponding to the acoustic signals to analog board **501**. The electrical signal generated by hydrophone **505** is provided to preamplifier **507**. Gain control circuit **511** is utilized to control the gain of preamplifier **507**. Analog filers **509** are utilized to condition the signal and eliminate noise components. Signal scaling circuit **513** is utilized to scale the signal to allow analog-to-digital conversion by analog-to-

digital conversion circuit **515**. The output of the analog-to-digital conversion circuit **515** is provided to a digital board **503** of acoustic tone receiver **200**. Filter **519** receives the digital output of analog-to-digital conversion circuit **515**. The output of digital filter **519** is provided as an input to code verification circuit **527**, which is depicted in **Figure 25**. Systems control logic circuit **521** is utilized for starting and resetting the digital circuit components of acoustic tone receiver **200**. The fire control logic **523** is similar to the control logic depicted in **Figure 26**. The fire control driver circuit **529** is utilized to supply current to an electrically actuable detonator circuit. Preferably, a detonator power supply **531** is provided to energize the detonation. Additionally, an abort circuit is present in abort control logic **525**.

Figure 28 is a flowchart depiction of the operations performed by the acoustic tone receiver **4200**. At flowchart block **541**, a signal is detected at the hydrophone. The signal is provided to the gain control amplifier in accordance with software block **543**. In accordance with software blocks **547**, **549**, the analog signal is examined and determined whether it is saturated, and determined whether it is detectable. If the signal is determined to be saturated in software block **547**, the process continues at software block **549**, wherein the gain is reduced. If it is determined at software block **549** that the signal is not detectable, then in accordance with software block **546**, the gain is increased. In accordance with software block **551**, it is determined whether or not the signal is resolvable. If the signal is resolvable, control is passed to software block **567**; however, if it is determined that the signal is not resolvable, in accordance with software block **553**, and **555**, a predetermined time interval is allowed to pass (during which the signal is examined to determine whether it is resolvable). If it is determined that the signal is not resolvable within the predetermined time interval, the actuation of the downhole tool associated with the acoustic tone

receiver **200** is aborted, in accordance with software block **555**. If it is determined at software block **551** that the signal is resolvable, and it is further determined at software block **567** that the signal is recognizable, then it is determined that a "tone" has been detected. The detection of a tone is represented by software block **565**. Software blocks **557** and **559** together determine whether a tone is detected in the appropriate time interval. Together software blocks **561**, **563**, **569**, and **571** determine whether or not a series of acoustic tones which have been detected correspond to a particular command signal which is associated with a particular wellbore tool. The series of acoustic tones can be considered to be either a series of binary characters, or a series of transmission frequencies which together define a command signal. The flowchart set forth in **Figure 7D** utilizes the transmission frequency analysis, and thus examines the signal frequency band for the series of acoustic tones. If the series of acoustic tones do not match the preprogrammed command signal, the process aborts in accordance with software block **571**; however, if the series of acoustic tones matches the programmed command signal, a firing circuit is enabled in accordance with software block **573**.

5. APPLICATIONS AND END DEVICES

Figures 31 through **43** will now be utilized to describe one particular use of the communication system of the present invention, and in particular to describe utilization of the communication system of the present invention in a complex completion activity. **Figure 31** is a schematic depiction of a completion string with a plurality of completion tools carried therein, each of which is selectively and remotely actuable utilizing the communication system of the present invention. More particularly, each particular completion tool in the string of **Figure 31** is identified with the particular command signal, prior to lowering the

completion string into the wellbore. The particular command signals are recorded at the surface, and utilized to selectively and remotely actuate the wellbore tools during completion operations in a particular operator-determined sequence. In the particular example shown in **Figure 31**, the completion string includes an acoustic tone circulating valve **601**, an acoustic tone filler valve **603**, an acoustic tone safety joint **605**, an acoustic tone packer **607**, an acoustic tone safety valve **609**, an acoustic tone underbalance valve **611**, an acoustic gun release **613**, and an acoustic tone select firer **615**, as well as a perforating gun assembly **617**. **Figure 32** is a schematic depiction of one preferred acoustic tone select firer **615** of **Figure 31**. As is shown, a plurality of acoustic tone select firing devices are carried along with an associated perforating gun. As is conventional, spacers may be provided between the perforating guns to define the distance between perforations within the wellbore.

Returning now to **Figure 31**, the operation of the various wellbore tools will now be described. Circulating valve **601** is utilized to control the flow of fluid between the central bore of the completion string and the annulus. The acoustic tone circulating valve **601** may be run-in in either an open condition or closed condition. A command signal may be communicated within the wellbore to change the condition of the valve to either prevent or allow circulation of fluid between the central bore of the completion string and the annulus. Acoustic tone filler valve **603** is utilized to prevent or allow the filling of the central bore of the completion string with fluid. The valve may be run in in either an open condition or a closed condition. The command signal uniquely associated with the acoustic tone filler valve **603** may be communicated in a wellbore to change the condition of the valve. Acoustic tone safety joint **605** is a mechanical mechanism which couples upper and lower portions of the completion string together. If the lower portion of the completion string becomes stuck, the acoustic tone safety

joint **605** may be remotely actuated to release the lower portion of the completion string and allow retrieval of the upper portion of the completion string. The acoustic tone safety joint is in a locked condition during run-in, and may be unlocked by directing the appropriate command signal within the wellbore. The acoustic tone packer set **607** is run into the wellbore in a radially reduced running condition. The packer may be set to engage and seal against a wellbore tubular such as a casing string. The acoustic tone safety valve **609** is a valve apparatus which includes a flapper valve component which prevents communication of fluid through the central bore of the completion string. Typically, the acoustic tone safety valve **609** is run into the wellbore in an open condition (thus allowing communication of fluid within the completion string); however, if the operator desires that the fluid path be closed, a command signal may be directed downward within the wellbore to move the acoustic tone safety valve **609** from an open condition to a closed condition. The acoustic tone underbalance valve **611** is provided in the completion string to allow or prevent an underbalanced condition. Therefore, it may be run into the wellbore in either an open condition or a closed condition. In a closed condition, the acoustic tone underbalance valve **611** prevents communication of fluid between the central bore of the completion string and the annulus. The acoustic tone gun release **613** couples the completion string to the acoustic tone select firer **615** and the tubing conveyed perforating gun **617**. The acoustic tone gun release **613** mechanically latches the completion string to the acoustic tone select firer **615** during running operations. If the operator desires to drop the perforating guns, and remove the completion string, a command signal is directed downward within the wellbore which causes the acoustic tone gun release to unlatch and allow separation of the completion string from the acoustic tone select firer **615** and tubing conveyed perforating gun **617**. The acoustic tone select firer **615** allows for the remote and

selective actuation of a particular tubing conveyed perforating gun **617** which is associated therewith.

Figure 32 depicts a multiple gun completion string. Each of these fire and gun assemblies may be mutually and selectively actuated by remote control commands which are initiated at a remote wellbore location, such as the surface of the wellbore.

Figure 33 is a longitudinal section view of a tool which can be utilized to house the sensors, electronics, and actuation mechanism, in accordance with the present invention. As is shown, actuator assembly **701** includes a sensor package assembly **703** which includes a central cavity **705** which communicates with the wellbore fluid through ports **709**. The housing includes internal threads **707** at its upper end to allow connection in a completion string. Sensor **711** (such as a hydrophone) is located within cavity 705. Electrical wires from sensor **711** are directed through Kemlon connectors **719, 721** to allow passage of the electrical signal indicative of the acoustic tone to the analog and digital circuit components. The sensor package housing is coupled to an electronics housing by threaded coupling **713**. Electronic housing **715** includes a sealed cavity **717** which carries the analog and digital circuit components described above. Both components are shown schematically as box **710**. The electric conductors provide the output of the electronics sub assembly through Kemlon connectors **725, 727** to chamber **729** which includes an igniter member as well as the power charge material. Preferably, the igniter comprises an electrically-actuated heating element which is surrounded by a primary charge. The primary charge serves to ignite the secondary power charge. In **Figure 35**, the igniter **731** is shown as communicating with sealed chamber **731**, which preferably forms a stationary cylinder body which can be filled with gas as the power charge ignites.

The gas can be utilized to drive a piston-type member, all of which will be discussed in detail further below.

Figure 34 is a cross sectional view of the assembly of **Figure 33** along section line C-C. As is shown, Kemlon connector **725, 727** are spaced apart in a central portion of a gas-impermeable plug **726**. **Figure 35** is a longitudinal sectional view as seen along sectional line A-A of **Figure 34**. As is shown, Kemlon connectors **725, 727** allow the passage of an electrical conductor into a sealed chamber. The electrical conductors are connected to firing mechanism **731** which includes electrically-actuated heating element **735** which is embedded in a primary charge **737**. Heat generated by passing electricity through heating element **735** causes primary charge **737** to ignite. Primary charge **737** is completely surrounded by a secondary charge **739**. Ignition of the primary charge **737** causes ignition of the secondary charge at **739**. The resulting gas fills the sealed chamber which drives moveable mechanical components, such as pistons.

The housing depicted in **Figures 32** and **33** are utilized by select firer **615** wherein a flow passage is not required. **Figures 36** and **37** depict sectional views of the configuration of the actuator components when a central bore is required. In **Figure 36**, completion string **751** as shown in cross sectional view. Central bore **752** defined therein for the passage of fluids. Preferably, the sensor assembly, analog and digital electrical components and actuator assembly are carried in cavities defined within the walls of the completion string. **Figure 36** depicts the Kemlon connectors **753, 755**, and the cavity **756** which is defined therein for tubular **751**. **Figure 37** is a longitudinal sectional view seen along section line A-A of **Figure 35**. As shown, Kemlon connectors **753, 755** allow the passage of electrical conductor into the sealed chamber. The electrical

conductors communicate with heating element **757** which is completely embedded in primary charge **759** which is surrounded by secondary charge of **761**. The passage of electrical current through heating element **757** causes primary charge **759** to ignite, which in turn ignites secondary charge **761**. The gas produced by the ignition of this material can be utilized to drive a mechanical component, in a piston-like manner.

Figures 38 through **43** schematically depict utilization of a power charge to actuate various completion tools, including those completion tools shown schematically in **Figure 31**. All of the valve components depicted schematically in **Figure 31** can be moved between open and closed conditions as is shown in **Figures** 38 and 39. **Figure 38** is a fragmentary longitudinal sectional view of a normally-closed valve assembly. As is shown, outer tubular **801** includes outer port **803** and inner tubular **805** includes inner port **807**. Piston member **809** is located intermediate outer tubular **801** and inner tubular **805** in a position which blocks the flow of fluid between outer port **803** and inner port **807**. Preferably, one or more seal glands, such as seal glands **811, 813** are provided to seal at the sliding interface of piston member **809** and the tubulars. Power charge **815** is maintained within a sealed cavity, and is electrically actuated by heating element **817**. When an operator desires to move the valve from a normally-closed condition to an open condition, a coded signal is directed downward within the wellbore, causing the passage of electrical current through heating element **817**, which generates gas which drives piston member **809** into a position which no longer blocks the passage of fluid between inner and outer ports **803, 807**.

Figure 39 is a fragmentary longitudinal sectional view of a normally-open valve. As is shown, outer tubular **801** includes outer port **803** and inner tubular **805** includes inner port **807**. Piston member **809** is located intermediate outer

tubular **801** and inner tubular **805** in a position which does not block the flow of fluid between outer port **803** and inner port **807**. Preferably, one or more sealed glands, such as seal glands **811, 813** are provided to seal at the sliding interface of piston member **809** and the tubulars. Power charge **815** is maintained within a sealed cavity, and is electrically actuated by heating element **817**. When an operator desires to move the valve from a normally-open condition to a close condition, a coded signal is directed downward within the wellbore, causing the passage of electrical current through heating element **817**, which generates gas which drives piston member **809** into a position which then blocks the passage of fluid between inner and outer ports **803, 807**.

Figure 40 is a simplified and fragmentary longitudinal sectional view of a safety joint which utilizes the present invention. As is shown, tubular **831** and tubular **833** are physically connected by locking dog **835**. Locking dog **835** is held in position by piston member **837**. When the operator desires to release tubular **831** from tubular **833**, a coded signal is directed downward into the wellbore. Upon detection, currents pass through heating element **843** which ignites power charge **839** within a sealed chamber, causing displacement of piston **837**. Displacement of piston **837** allows locking dog **835** to move, thus allowing separation of tubular **831** from tubular **833**.

Figure 41 is a simplified longitudinal sectional view of a packer which may be set in accordance with the present invention. As is shown, piston member **855** is located between outer tubular **851** and inner tubular **853**. One end of piston **855** is in contact with a sealed chamber which contains power charge **857**. Heating element **859** is utilized to ignite power charge **857**, once a valid command has been received. The other end of piston member **855** is a slip **861** which engages slip **863**. Together, slips **861, 863** serve to energize and expand

radially outward elastomer sleeve **865** which may be buttressed at the other end by buttress member **867**.

Figure 42 is a simplified and schematic partial longitudinal depiction of a flapper valve assembly. As is shown, a flapper valve **875** is located intermediate outer tubular **871** and inner tubular **873**. As is shown, flapper valve **875** is retained in a normally-open position by inner tubular **873**. Spring **877** operates to bias flapper valve **875** outward to obstruct the flowpath of a completion string. A sealed chamber **880** is provided which is partially filled with a power charge **879** which may be ignited by heating element **881**. Differential areas may be utilized to urge inner tubular **873** upward when power charge is ignited. Movement of inner tubular **873** upward will allow spring **877** to bias flapper valve **875** outward into an obstructing position. In accordance with the present invention, when an operator desires to move normally-open flapper valve to a closed position, the command signal associated with particular flapper valve is communicated into the wellbore, and received by the acoustic tone receiver. If the command signal matches the pre-programmed code, an electrical current is passed through heating element **881**, causing displacement of inner tubular **873**, and the outward movement of flapper valve **875**.

Figure 43 is simplified and schematic depiction of the operation of the firing system for tubing conveyed perforating guns. As is shown, the passing of electrical current through heating element **891** causes the ignition of power charge **893** within a sealed chamber which generates gas which drives firing pin **895** into physical contact with a percussive firing pin **897** which serves to actuate perforating gun **899**.

6. LOGGING DURING COMPLETIONS

An alternative embodiment of the present invention will now be described which utilizes an acoustic actuation signal sent from a remote location (typically, a surface location) to a subsurface location which is associated with a particular completion or drill stem testing tool. The coded signal is received by any conventional or novel acoustic signal reception apparatus, including the reception devices discussed above, but preferably utilizing a hydrophone. The acoustic transmission is decoded and, if it matches a particular tool located within the completion and drill stem testing string, a power charge is ignited, causing actuation of the tool, such as switching the tool between mechanical conditions such as set or unset conditions, open or closed conditions, and the like.

In accordance with the present invention, particular ones (and sometimes all) of the mechanic devices located within the completion and drill stem testing string are also equipped with a transmitter device which may be utilized to transmit information, such as data and commands, from a particular tool to a remote location, such as a surface location where the data may be recovered, recorded, and interpreted. In accordance with the present invention, the acoustic tone generator is utilized for transmitting information (such as data and commands) away from the tool. In the preferred embodiment of the present invention, the acoustic tone generator need not necessarily utilize its ability to adapt the communication frequencies to the particular communication channels, since that particular feature may not be necessary.

In accordance with the present invention, a processor is provided within the downhole tools in order to process a variety of sensor data inputs. In the preferred embodiment of the present invention, the sensor inputs include: (1) a measure of the noise generated by fluid as it is produced through perforations in

the wellbore tubulars; (2) downhole temperature; (3) downhole pressure; and (4) wellbore fluid flow. In the preferred embodiment of the present invention, the downhole noise that is measured is subjected to a Fourier (or other) transform into the frequency domain. The frequency domain components are analyzed in order to determine: (1) whether or not flow is occurring at that particular time interval, or (2) the likely rate of flow of wellbore fluids, if flow is detected.

In the preferred embodiment of the present invention, a redundancy is provided for the sensors, the processors, the receivers, and the transmitters provided in the various tools in the completion and drill stem testing string. This is especially important since, during perforating operations, significant explosions occur which may damage or impair the operation of the various sensors, processors, and communication devices.

In the preferred embodiment of the present invention, the downhole processors are utilized to monitor sensor data and actuate one or more subsurface valves in a predetermined and programmed manner in order to perform drill stem test operations. Such operations occur after the casing has been perforated. The operating steps include:

(1) utilizing an acoustic sensor (such as the hydrophone) in order to determine whether or not a wellbore flow has commenced;

(2) utilizing the controller to actuate the one or more valves which allow communication of fluid between an adjacent zone and the completion string;

(3) allowing wellbore fluid buildup for a predetermined interval;

(4) all the while, sensing temperature and pressure of the wellbore fluid;

(5) opening the valves to allow flow;

(6) monitoring temperature, pressure, flow, and the subsurface acoustic noise in order to generate data pertaining to the production;

(7) intermittently communicating data to the surface pertaining to the drill stem test; and

(8) recording raw and processed data in memory for either retrieval with the string or transmission to the surface utilizing acoustic signals or through a wireline conveyed data recorder/retriever.

These and other objectives and advantages will be readily apparent with the reference to **Figures 44A** through **51**.

Figure 44A is a pictorial representation of wellbore **2001** which extends through formation **2003**, and which utilizes casing string **2005** to prevent the collapse or deterioration of the wellbore. Completion string **2007** extends downward through casing **2005**. A central bore **2009** is defined within completion string **2007**. Completion string **2007** serves several functions. First, it serves to carry completion tools from a surface location to a subsurface location, and allows for the positioning of the completion tools adjacent particular zones of interest, such as Zone 1 and Zone N which are depicted in **Figure 46A**. Second, completion string **2007** is utilized for the passing of fluids downward from a surface location to a subsurface location (such as a formation of interest) during the completion operations, as well as to allow for the passage upward of wellbore

fluids through central bore **2009** and/or the annular space during and after drill stem test operations. In the view of **Figure 44A**, completion string **2007** is shown as locating completion tools adjacent Zone 1 and Zone N. The tools carried adjacent Zone 1 include upper packer **2011**, perforating gun **2013**, valve **2015**, and lower packer **2017**. Likewise, completion string **2007** locates other completion tools adjacent Zone N, including upper packer **2019**, perforating gun **2021**, valve **2023**, and lower packer **2025**. During completion and drill stem test operations, the upper and lower packers are utilized to seal the region between tubing string **2007** and casing string **2005**. The perforating guns **2013**, **2021** are then fired to perforate the adjacent casing and allow for the passage of wellbore fluid from the formation **2003** into wellbore **2001**. The valves **2015**, **2023** are provided to selectively allow for the passage of fluids between central bore **2009** of completion string **2007** and the zones of interest (such as Zone 1 and Zone N).

In the view of **Figure 44A**, upper and lower packers are utilized to straddle a relatively narrow geological formation of interest. **Figure 44B** depicts an alternative configuration which may be utilized with the present invention, which does not utilize packers to straddle the formation. As in shown in **Figure 44B**, completion string **2020** is shown as being packed off against casing **2024** by packer **2027**, which forms a fluid and gas tight seal, which prevents the flow or migration of wellbore fluids upward through the annular region between completion string **2020** and casing **2024**. Two perforating gun assemblies are located beneath packer **2027**. In accordance with the present invention, each is equipped with control and monitoring electronics.

As is shown in **Figure 44B**, perforating gun **2031** has associated with it control and monitoring electronics **2029**. In the view of **Figure 44B**, perforating gun **2031** is depicted as it blasts perforations through casing **2024**. Likewise,

perforating gun **2035** has associated with it control and monitoring electronics **2033**. Perforating gun **2035** is likewise shown as it blasts perforations through casing **2024**. As discussed above in detail, in accordance with the present invention, each of these perforating guns is responsive to a different, acoustically transmitted actuation signal which is communicated from a surface location (preferably, but not necessarily) through the wellbore fluid and tubulars. When the control and monitoring electronics **2029**, **2033** detect a "match", an ignition is triggered which causes the perforation of casing **2024**.

Figure 45 is a block diagram depiction of the surface and subsurface electronics and processing utilized in the preferred embodiment of the present invention. As is shown, a surface system **2041** communicates through a medium **2045** (such as a column of wellbore fluid, a wellbore tubular string, or a combination since the acoustic signal may migrate between fluid and tubular pathways within the wellbore or, alternatively, transmission may occur through the formations between the surface location and the subsurface location). As is shown, surface system **2041** includes an acoustic transmitter **2047** and an acoustic receiver **2049**, which are both acoustically coupled to transmission medium **2045**. The subsurface system **2043** includes an acoustic receiver **2051** and an acoustic transmitter **2053** which are likewise acoustically coupled to transmission medium **2045**. The acoustic transmitters and receivers may comprise any of the above described transmitters or receivers, or any other conventional or novel acoustic transmitters or receivers.

The subsurface system **2041** will now be described with reference to **Figure 45**. As is shown, processor **2055** (and the other power consuming components) receives power from power source **2057**. Processor **2055** is programmed to actuate transmitter driver **2059**, which in turn actuates acoustic

transmitter **2047**. Processor **2055** may comprise any conventional processor or industrial controller; however, in the preferred embodiment of the present invention, processor **2055** is a processor suitable for use in a general purpose data processing device. Processor **2055** utilizes random access memory **2061** to record data and program instructions during data processing operations. Processor **2055** utilizes read-only memory **2063** to read program instructions. Processor **2055** may display or print data and receive data, commands, and user instructions through input/output devices **2065**, **2067**, which may comprise video displays, printers, keyboard input devices, and graphical pointing devices.

In operation, processor **2055** utilizes transmitter driver **2059** to actuate acoustic transmitter **2047** in accordance with program instructions maintained in RAM **2061**, ROM **2063**, as well as commands received from the operator through input/output devices **2065**, **2067**.

Acoustic receiver **2049** is adapted to detect acoustic transmissions passing through transmission medium **2045**. The output of acoustic receiver **2049** is provided to signal processing **2069** where the signal is conditioned. The analog signal is passed to analog-to-digital device **2071**, where the analog signal is digitized. The digitized data may be passed through digital signal processor **2073** which may provide one or more buffers for recording data. The data may then pass from digital signal processor **2073** to processor **2055**.

In the present invention, it is not necessary that acoustic transmitter **2047** and acoustic receiver **2049** transmit and/or detect the same type of acoustic signals. In the preferred embodiment of the present invention, the acoustic receiver **2049** is preferably of the type described above as an "acoustic tone generator", in order to accommodate relatively large amounts of data which may

be passed from the subsurface system **2043** to the surface system **2041** for recordation and analysis. The acoustic transmitter **2047** is solely utilized to transmit relatively simple commands, or other information such as analysis parameters for downhole use during analysis and/or processing, into the wellbore, and thus need not generally accommodate large data rates. Accordingly, the acoustic transmitter **2047** may comprise one of the relatively simple transmission technologies discussed above, such as the positive pressure pulse apparatus.

The preferred subsurface system **2043** will now be described with reference to **Figure 45**. As is shown, acoustic receiver **2051** is acoustically coupled to communication medium **2045**. Acoustic signals which are transmitted from surface system **2041** are detected by acoustic receiver **2051** and passed to signal processing and filtering unit **2075**, where the signal is conditioned. The signal is then passed to code or frequency verification module **2077**, which operates in the manner discussed above. If there is a match between the code associated with the particular subsurface system **2043** and the detected acoustic transmission, then fire control module **2079** is actuated, which initiates charge **2081**, which is utilized to mechanically actuate end device **2083**. All of the foregoing has been discussed above in great detail.

In this particular and preferred embodiment of the present invention, acoustic receiver **2051** serves a dual function: first, it is utilized to detect coded actuation commands which are processed as described above; second, it is utilized as an acoustic listening device which passes wellbore "noise" for processing and analysis. As is shown, a variety of inputs are provided to signal processing/analog-to-digital and digital signal processing block **2091**, including: the output of acoustic receiver **2051**, the output of temperature sensor **2085**, the

output of pressure sensor **2087**, and the output of flow meter **2089**. All of the sensor data is provided as an input to processor **2095** which is powered by power supply **2093** (as are all the other power-consuming electrical components). Processor **2095** is any suitable microprocessor or industrial controller which may be pre-programmed with executable instructions which may be carried in either or both of random access memory **2097** and read-only memory **2099**. Additionally, processor **2095** may communicate through input/output devices **3001**, **3003**, in a conventional manner, such as through a video display, keyboard input, or graphical pointing device. In accordance with the present invention, processor **2095** is not equipped with such displays and input devices in its normal use but, during laboratory use and testing, keyboards, video displays, and graphical pointing devices may be connected to processor **2095** to facilitate programming and testing operations. In accordance with the present invention, processor **2095** is connected to one or more end devices, such as end device **3007** and end device **3009**. During drill stem test operations, end devices **3007**, **3009** preferably comprise the valves which are utilized to check or allow the flow of fluids between the formation and the wellbore. The use of valves during drill stem test operations will be described in greater detail below. As is shown in **Figure 45**, processor **2095** is connected through driver **3005** to acoustic transmitter **2053**. In this manner, processor **2095** may communicate data or commands to any surface or subsurface location. For example, processor **2095** may be programmed with instructions which require processor **2095** to generate an actuation command for another wellbore end device, once a predetermined wellbore condition has been detected. As another example, processor **2095** may be programmed with instructions which require processor **2095** to utilize acoustic transmitter **2053** to communicate processed or raw data from a subterranean location to a remote location, such as a surface location, to allow recordation and analysis of the data.

The present invention is contemplated for use during completion operations. Consequently, the downhole electronics and processing components are exposed to high temperatures, high pressures, high velocity fluid flows, corrosive fluids, and abrasive particulate matter. Additionally, those components are also subject to intense shock waves and pressure surges associated with perforating operations. While many electrical and electronic components have been ruggedized to withstand hostile environments, during completion operations, the risk of failure is not negligible. Accordingly, in accordance with the present invention, a "redundancy" in the electrical and electronic components is provided in order to minimize the possibility of a tool failure which would require an abortion of the completion operations and retrieval of the equipment. This redundancy is depicted in block diagram form in **Figure 46**. As is shown, "module" **3011** is made up of primary-electronics subassembly **3113**, backup electronics subassembly **3015**, and end device of assembly **3017**. Preferably, end device **3017** comprises any conventional or novel end device, such as a packer, perforating gun or valve. As is shown, primary electronics subassembly **3113** includes acoustic receiver/sensor **3021**, acoustic transmitter **3023**, pressure sensor **3025**, temperature sensor **3027**, flow sensor **3029**, and processor **3031**. Backup electronic subassembly **3015** includes acoustic receiver/sensor **3033**, acoustic transmitter **3035**, pressure sensor **3037**, temperature sensor **3039**, flow sensor **3041**, and processor **3043**. The redundant system can operate under any of a number of conventional or available redundancy methodologies. For example, the primary electronic subassembly **3113** and the backup electronic subassembly **3015** may operate simultaneously during completion and drill stem test operations. In this manner, each processor can check and compare measurements and calculations at each critical step of processing in order to determine a measure of the operating condition of each subassembly.

Alternatively, one subassembly (such as the primary electronic subassembly **3113**) may be utilized solely until it is determined by processor **3113,** or by the human operators at the surface location, that primary electronic subassembly **3113** is no longer operating properly; in that event, a command may be directed from the surface location to the subsurface location, activating backup electronic subassembly **3115** which can replace primary electronic subassembly **3113**. It should be appreciated that any selected number of redundant or backup electronic subassemblies may be provided with each tool in order to provide greater assurance of the operational integrity of the completion and drill stem testing tools.

The basic operation of the improved completion system of the present invention will now be described with reference to **Figure 47**. As is shown, potential communication channels composed of steel and/or rubber **3055** and fluid **3053** extend through Zone 1, Zone 2, Zone 3, and Zone N. Within Zone 1, processor **3065** is responsive to input in the form of commands **3055** which are received from a surface or subsurface location, detected sound **3057**, detected temperature **3059**, detected pressure **3061**, and detected flow **3063**. Processor **3065** is preprogrammed with executable program instructions which require the processor to receive the input and perform particular predefined operations. In the view of **Figure 47**, some exemplary output activities are depicted, such as flow control **3067**, record raw data **3069**, process data **3071**, and transmit raw or processed data **3073**. In accordance with the flow control **3067**, processor **3065** may be utilized to open and/or close a particular valve or valves associated with processor **3065** in order to permit, block, or moderate the flow of fluids between the completion string and the wellbore. This is particularly useful during drill stem test operations, wherein flow is blocked for a predefined interval, and pressures are recorded in order to evaluate the adjoining producing formation.

Processor **3065** may utilize electrically actuable tool control means for moving the valve or valves between flow positions or conditions. The step of "record raw data" **3069** serves multiple purposes. First, the raw data may be preserved for later processing and analysis by a microprocessor **3065**. Alternatively, the raw data may be preserved in memory for eventual retrieval, by either physical removal of the completion string or transfer of the data by any conventional wireline or other data recording devices. The step of "process data" **3071** contemplates a variety of data processing activities, such as generating historical records of high and low values for temperature, pressure, and flow, generating rolling averages of values for temperature, pressure, and flow, or any other conventional or novel manipulation of the censored data. Alternatively, the process data step **3071** may include local control by processor **3065** of the end devices in order to moderate the flow of wellbore fluids in accordance with predetermined flow criteria, such as particular flow volumes or flow velocities. For example, processor **3065** may monitor wellbore temperatures and pressures, and open or close end devices to moderate the flow in accordance with a predetermined flow value associated with particular temperatures and pressures. The step of transmit raw or processed data **3073** comprises the passing through acoustic transmissions of either raw or processed data from processor **3065** to any other surface or subsurface location.

As is also shown in **Figure 47**, processor **3085** receives as an input detected commands **3007**, detected sounds **3077**, detected temperatures **3079**, detected pressures **3081**, and detected flows **3083**. Processor **3085** operates like processor **3065** to provide any of the following outputs or perform any of the following tasks: flow control **3087**, record raw data **3089**, process data **3091**, and transmit raw or processed data **3093**. Processor **3085** is associated with Zone 2,

and the sensed data that it receives relates to Zone 2, which may not be connected to Zone 1 except through the wellbore.

Likewise, processor **4005** is associated with Zone 3, and receives as input sensed commands **3095**, sensed sound **3097**, sensed temperature **3099**, sensed pressure **4001**, and sensed flow **3003**. Processor **4005** may obtain any number of the following outputs or perform any of the following tasks: flow control **4007**, record raw data **4009**, process data **4011**, and transmit raw or processed data **4013**.

Zone N is a zone that is isolated from Zones 1, 2 and 3. As with the other zones, Zone N may receive or transmit acoustic signals through either the fluid or the steel and rubber which comprise conventional completion strings. Processor **4025** receives as an input detected commands **4015**, detected sound **4017**, detected temperatures **4019**, detected pressures **4021**, and detected flow **4023**. Processor **4025** may provide any one of the following outputs: flow control **4026**, record raw data **4029**, process data **4031**, and transmit raw or processed data **4033**.

It should be apparent from the foregoing that the present invention allows for local processing and control of each zone either independently of one another or in a coordinated fashion, since each zone can communicate data or commands through the transmission and reception of acoustic signals through either the formation itself, the wellbore fluids, or the wellbore tubulars, such as the completion string and/or casing. Additionally, the activities of the various processors can be monitored and controlled from a surface location by either an automated system or by a human operator.

The use of an acoustic receiver or sensing device to monitor subterranean sounds or noise will now be discussed in detail. In the prior art, logging sondes have been lowered into wells in order to monitor subterranean sounds in order to determine one or more attributes about the wellbore. Typically, the sondes include a receiver which travels upward and downward within the wellbore on the wireline, mapping detected sounds (and temperature) with wellbore depth. This process is described in an article entitled *"Temperature and Noise Logging for Non-Injection Related Fluid Movement"* by R. M. McKinley of Exxon Production Research Company of Houston, Texas 77252-2189. This logging technique is premised upon the realization that fluid flow, particularly fluid expansion through constrictions, such as perforations, creates audible sounds that are easily distinguishable from the background noise. **Figure 48** is a graphical plot of frequency in hertz versus the spectral density of a Fourier transform of noise monitored in a test well versus the spectral density of the noise. This graph is a test result from the McKinley article. As is shown, the acoustic sound or noise detected from flow is represented in this graph by the solid line **3041**. Note that the sounds associated with the flow are significant in comparison with the background noise which is depicted by the dashed line **3043**. The detected noise associated with the flow has two significant peaks: peak **3045** and peak **3047**. In the McKinley article it was determined that peak **3045** (also labeled with "A") corresponds to the chamber resonance whose amplitude and frequency depend upon the environment. McKinley also concluded that the second peak **3047** (also identified by "B") corresponds to the fluid turbulence which has an amplitude that is dependent upon the rate of flow.

In accordance with the present invention, in a test environment, a variety of wellbore geometries and flow rates are monitored and recorded in order to determine the spectral profile associated with different geometries and different

flow rates. Additionally, the same testing can be conducted, using different types of fluids (that is with different compositions, densities, and suspended particulate matter).

A data base of these different profiles can be amassed and stored in computer memory. Before the completion string is run to the wellbore, the operator selects the spectral profile or profiles which more likely match the particular completion job which is about to be performed. The processors are programmed to perform Fourier transforms on detected noise at particular pre-defined intervals during the completion operation. The transformed detected data may be compared with one or more spectral profiles that are likely to be encountered in the particular completion job. Based upon the library of spectral profiles and the sensed data, the downhole processors can determine the likely fluid velocity of fluid entering the wellbore through the perforations. This information may be recorded in memory or processed and transmitted to the surface utilizing acoustic transmissions. This noise data can provide a reliable confirmation that good perforations have been obtained in the zone or zones of interest. Additionally, this noise data can be utilized intermittently throughout drill stem test operations in order to quantify the rates and volumes of fluid flow from different zones of interest.

Figure 49 is a flowchart representation of a data processing implemented monitoring of noise data. The process begins at software block **3051** and continues at software block **3053**, wherein the hydrophone or any other noise receiver is utilized to sense and condition sound data within the wellbore in the region of the zone of interest. Then, in accordance with software block **3055**, the sound data is digitized. Preferably, in accordance with software block **3057**, the raw digitized data is recorded for subsequent processing. Then, in accordance

with software block **3059**, the processor generates a frequency domain transform for a defined time interval, utilizing the recorded data. Preferably, a Fourier transform is utilized to map time-domain sensed data into the frequency domain. Then, in accordance with software block **3061**, the controller is utilized to compare the frequency domain data to preselected criteria. The preselected criteria may be developed by the controller from the library of test data, or it may be communicated to the controller from the surface. Next, in accordance with software block **3063**, the controller is utilized to calculate the flow rate from the frequency domain data. As discussed above, the amplitude from the amplitude of the second peak of the frequency domain data. Then, in accordance with software block **3065**, the controller records the flow rate data. Then, optionally, the controller transmits the flow data to a surface or subterranean location, and the process ends at software block **3069**.

During completion and drill stem test operations, the controller is also processing, recording, and transmitting temperature, pressure, and flow data, as is depicted in simplified form in **Figure 50**. The process begins at software block **3071** and continues at software block **3073**, wherein the controller utilizes the sensors to sense temperature, pressure, and flow data. Next, in accordance with software block **3075**, the sensed and conditioned analog data is digitized. Next, in accordance with software block **3077**, the digitized data is recorded in memory. Then, in accordance with software block **3079**, the controller processes the temperature, pressure and flow data in any conventional or novel manner. For example, the processor may generate a record of recorded highs and lows for temperature, pressure, and flow. Alternatively, the processor may generate rolling averages for temperature, pressure and flow for predefined intervals. In accordance with software block **3081**, the processor transmits processed temperature, pressure, and flow data to any subsurface or surface location for

further use and/or analysis. Then, in accordance with software block **3083**, the processor records the processed values for temperature, pressure and flow, and the process ends at software block **3085**.

Figure 51 provides in flow chart form a broad overview of a completion and drill stem test operation, which commences at software block **3087**. In software block **3089**, an acoustic signal is transmitted from a surface to a subsurface location in order to set packer number 1. In software block **3091**, the acoustic signal is received and decoded, resulting in setting of packer number 1 in accordance with software block **3093**. Then, in accordance with software block **3095**, it is determined whether other packers need to be set; if not the process advances to software block **4001**; if so, the process continues at software blocks **3097**, **3099**, and **4000**, wherein a "set packer 2" signal is transmitted and received, and packer number 2 is set.

Then, in accordance with software block **4001**, an acoustic signal is transmitted from the surface to a subsurface location which is intended to initiate the firing of perforating gun number 1. In accordance with software block **4003**, the acoustic signal is received and processed, and initiates the firing of perforating gun number 1 in accordance with software block **4005**. Then, in accordance with software block **4007**, the fire sequence is repeated for all guns between packer number 1 and packer number 2, if there are others.

Then, in accordance with software block **4009**, the one or more local processors are utilized to monitor the sounds or noise in the region of the zone of interest. Next, in accordance with software block **4001**, the controller records data, or transmits signals to the surface, which verify the flow of fluids into the wellbore and thus provide a positive indication that the casing has been successfully perforated. Next, in accordance with software block **4013**, the

controller sets the valve to shut in the flow for the drill stem test operation. Then, in accordance with software blocks **4015**, **4017**, the controller monitors pressure and transmits pressure data to the surface. The process continues for so long as the operator desires to gather drill stem test data. At the completion of the drill stem test operations, the valves are switched to an open condition to allow flow of fluid into the wellbore. The well may be then be killed and the completion and drill stem test string removed from the well, or the completion string may be maintained in position to serve as the production conduit. In either event, the controller is utilized to actuate the valves and set their positions to obtain the completion and/or production goals established by the well operator. The process ends at software block **4019**.

While the invention has been shown in only one of its forms, it is not thus limited but is susceptible to various changes and modifications without departing from the spirit thereof.

What is claimed is:

1. A method of communicating a control signal in a wellbore between a transmission node and a reception node, through an acoustic transmission pathway extending therebetween, comprising the method steps of:

providing a transmission apparatus at said transmission node which is in communication with said acoustic transmission pathway, for generating a series acoustic transmission which includes a control signal;

providing a reception apparatus at said reception node which includes:

(a) a sensor assembly which detects said series acoustic transmission;

(b) means for decoding said control-signal from said series acpistoc transmission;

utilizing said transmission apparatus to generate said series acoustic transmission; and

utilizing said reception apparatus to detect and decode said series acoustic transmission.

2. A method of communicating according to Claim 1:

wherein said reception apparatus further includes:

(c) a clock means for generating a synchronized clock signal;

wherein said means for separating utilizes said synchronized clock signal in separating said control signal from said series acoustic transmission.

3. A method of communicating according to Claim 1:

wherein said reception apparatus further includes:

(c) a demodulator which maps a predefined plurality of available control signals to a predefined output at a particular one of a plurality of available output pins.

4. A method of communicating according to Claim 3, further including:

an electrically actuable wellbore tool which is electrically coupled to a particular one of said plurality of available output pins, and which is actuated by said predefined output.

5. A method of communicating according to Claim 4, further including:

an electrically-actuable wellbore tool which is electrically coupled to said reception apparatus through said actuation circuit, and which switches between a plurality of available operating conditions in response to said actuation circuit.

6. A method of communicating according to Claim 3:

wherein said reception apparatus further includes:

(d) means for translating said series acoustic transmission into a parallel input control signal to said demodulator.

7. A method of communicating a control signal in a wellbore between a transmission node and a reception node, through an acoustic transmission pathway extending therebetween, comprising the method steps of:

providing a transmission apparatus at said transmission node which is in communication with said acoustic transmission pathway, for generating a control signal in the form of a series acoustic transmission which is transmitted at a rate defined by a clock signal;

providing a reception apparatus at said reception node which includes:

(a) a sensor assembly which detects said series acoustic transmission;

(b) means for decoding said control signal from said series acoustic transmission

utilizing said transmission apparatus to generate said series acoustic transmission; and

utilizing said reception apparatus to detect and decode said series acoustic transmission.

8. A method of communicating according to Claim 7:

wherein said reception apparatus further includes:

(c) a clock means for generating a synchronized clock signal;

wherein said means for separating utilizes said synchronized clock signal in decoding said control signal from said clock signal.

9. A method of communicating according to Claim 7:

wherein said reception apparatus further includes:

(c) a demodulator which maps a predefined plurality of available control signals to a predefined output at a particular one of a plurality of available output pins.

10. A method of communicating according to Claim 9, further including:

an activation circuit which is electrically coupled to a particular one of said plurality of available output pins, and which is actuated by said predefined output.

11. A method of communicating according to Claim 10, further including:

an electrically-actuable wellbore tool which is electrically coupled to said reception apparatus through said actuation circuit, and which switches between a plurality of available operating conditions in response to said actuation circuit.

12. A method of communicating according to Claim 9:

wherein said reception apparatus further includes:

(d) means for translating said series acoustic transmission into a parallel input control signal to said demodulator.

13. An apparatus for communicating a control signal in a wellbore between a transmission node and a reception node, through an acoustic transmission pathway extending therebetween, compromising:

a transmission apparatus at said transmission which is in communication with said acoustic transmission pathway, for generating a series acoustic transmission which is representative of a bit-by-bit product of a multiple-bit binary control signal and a clock signal;

(a) a sensor assembly which detects said series acoustic transmission;

(b) means for decoding said multiple-bit binary control signal from said series acoustic transmission;

wherein, during a communication mode of operation;

(a) said transmission apparatus is utilized to generate said series acoustic transmission; and

(b) said reception apparatus is utilized to detect and decode said series acoustic transmission.

14. A method of communicating according to Claim 13:
wherein said reception apparatus further includes:

(c) a clock means for generating a synchronized clock signal;

wherein said means for decoding utilizing said synchronized clock signal in separating said multiple-bit binary control signal from said clock signal.

15. A method of communicating according to Claim 13:

wherein said reception apparatus further includes:

(c) a demodulator which maps a predefined plurality of available multiple-bit binary control signals to a predefined output at a particular one of a plurality of available output pins.

16. A method of communicating according to Claim 15, further including:

an activation circuit which is electrically coupled to a particular one of said plurality of available output pins, and which is actuated by said predefined output.

17. A method of communicating according to Claim 16, further including:

an electrically-actuable wellbore tool which is electrically coupled to said reception apparatus through said actuation circuit, and which switches between a plurality of available operating conditions in response to said actuation circuit.

18. A method of communicating according to Claim 15:

wherein said reception apparatus further includes:

(d) means for translating said series acoustic transmission into a parallel input control signal to said demodulator.

19. A method of performing at least one of (1) a completion operation, and (2) a drill stem test operation, in a wellbore, comprising:

providing a wellbore tubular string;

providing a plurality of discrete and individually actuable wellbore tools, including:

(a) at least one perforating gun;

(b) at least one packer;

(c) at least one valve;

(d) each having (1) a force responsive member, (2) a gas generating member, and (c) a trigger member;

providing at least one acoustic receiver for said plurality of discrete and individually actuable wellbore tools for selectively activating a particular trigger member upon receipt of a particular acoustic command;

securing said plurality of discrete and individually actuable wellbore tools in particular and predetermined locations within said wellbore tubular string;

lowering said wellbore tubular string into said wellbore;

transmitting a series of acoustic commands into said wellbore;

utilizing said at least one acoustic receiver to detect said series of acoustic commands, and to individually activate said trigger member of each of said plurality of discrete and individually actuable wellbore tools which is associated with each particular acoustic command of said series of acoustic commands in order to cause application of force from said gas generating member to said force responsive member to perform at least one of (1) a completion operation, and (2) a drill stem test operation through the sequential actuation of particular ones of said discrete and individually actuable wellbore tools.

20. A method according to Claim 19, wherein said discrete and individually actuable wellbore tools further include at least one of:

(a) a safety joint;

(b) a gun release;

(c) a circulating valve; and

(d) a filler valve.

21. A method according to Claim 19, wherein said at least one acoustic receiver comprises a discrete acoustic receiver for each of said plurality of discrete and individually actuable wellbore tools.

22. A method according to Claim 19, wherein said at least one acoustic receiver includes at least one programmable controller for decoding said series of acoustic commands and for determining which particular one of said plurality of discrete and individually actuable wellbore tools is to be actuated for each particular acoustic command.

23. An apparatus for performing at least one of (1) a completion operation, and (2) a drill stem test operation, in a wellbore, comprising:

a wellbore tubular string;

a plurality of discrete and individually actuable wellbore tools, including:

(a) at least one perforating gun;

(b) at least one packer;

(c) at least one valve;

(d) each having (1) a force responsive member, (2) a gas generating member, and (c) a trigger member;

(e) each being secured in particular and predetermined locations within said wellbore tubular string;

at least one acoustic receiver for said plurality of discrete and individually actuable wellbore tools for selectively activating a particular trigger member upon receipt of a particular acoustic command;

a transmitter for transmitting a series of acoustic commands into said wellbore;

wherein, during a control mode of operation, said at least one acoustic receiver is utilized to detect said series of acoustic commands, and to individually activate said trigger member of each of said plurality of discrete and individually actuable wellbore

tools which is associated with each particular acoustic command of said series of acoustic commands in order to cause application of force from said gas generating member to said force responsive member to perform at least one of (1) a completion operation, and (2) a drill stem test operation through the sequential actuation of particular ones of said discrete and individually actuable wellbore tools.

24. An apparatus according to Claim 23, wherein said discrete and individually actuable wellbore tools further include at least one of:

(a) a safety joint;

(b) a gun release;

(c) a circulating valve; and

(d) a filler valve.

25. An apparatus according to Claim 23, wherein said at least one acoustic receiver comprises a discrete acoustic receiver for each of said plurality of discrete and individually actuable wellbore tools.

26. An apparatus according to Claim 23, wherein said at least one acoustic receiver includes at least one programmable controller for decoding said series of acoustic commands and for determining which particular one of said plurality of discrete and individually actuable wellbore tools is to be actuated for each particular acoustic command.

27. A method of performing at least one of (1) a completion operation, and (2) a drill stem test operation, in a wellbore, comprising:

providing a wellbore tubular string;

providing a plurality of discrete and individually actuable wellbore tools, including:

(a) at least one perforating gun;

(b) at least one packer;

(c) at least one valve;

(d) each having (1) a force responsive member, (2) a gas generating member, and (c) a trigger member;

providing at least one receiver for said plurality of discrete and individually actuable wellbore tools for selectively activating a particular trigger member upon receipt of a particular command;

securing said plurality of discrete and individually actuable wellbore tools in particular and predetermined locations within said wellbore tubular string;

lowering said wellbore tubular string into said wellbore;

transmitting a series of commands into said wellbore;

utilizing said at least one receiver to detect said series of acoustic commands, and to individually activate said trigger member of each of said plurality of discrete and individually actuable wellbore tools which is associated with each particular command of said series of commands in order to cause application of force from said gas generating member to said force responsive member to perform at least one of (1) a completion operation, and (2) a drill stem test operation through the sequential actuation of particular ones of said discrete and individually actuable wellbore tools.

28. A method according to Claim 27, wherein said discrete and individually actuable wellbore tools further include at least one of:

(a) a safety joint;

(b) a gun release;

(c) a circulating valve; and

(d) a filler valve.

29. A method according to Claim 27, wherein said at least one receiver comprises a discrete receiver for each of said plurality of discrete and individually actuable wellbore tools.

30. A method according to Claim 27, wherein said at least one receiver includes at least one programmable controller for decoding said series of commands and for determining which particular one of said plurality of discrete and individually actuable wellbore tools is to be actuated for each particular command.

31. An apparatus for performing at least one of (1) a completion operation, and (2) a drill stem test operation, in a wellbore, comprising:

a wellbore tubular string;

a plurality of discrete and individually actuable wellbore tools secured to said wellbore tubular string, including:

(a) at least one perforating gun;

(b) at least one packer;

(c) at least one valve;

(d) each having (1) a force responsive member, (2) a gas generating member, and (c) a trigger member;

at least one receiver for said plurality of discrete and individually actuable wellbore tools for selectively activating a particular trigger member upon receipt of a particular command;

a transmitter for transmitting a series of commands into said wellbore;

wherein, during a control mode of oerpation, said at least one receiver is utilized to detect said series of commands, and to individually activate said trigger member of each of said plurality of discrete and individually actuable wellbore tools which is associated with each particular command of said series of commands in order to cause application of force from said gas generating member to said force responsive member to perform at least one of (1) a completion operation, and (2) a drill stem test operation

through the sequential actuation of particular ones of said discrete and individually actuable wellbore tools.

32. An apparatus according to Claim 31, wherein said discrete and individually actuable wellbore tools further include at least one of:

(a) a safety joint;

(b) a gun release;

(c) a circulating valve; and

(d) a filler valve.

33. An apparatus according to Claim 31, wherein said at least one receiver comprises a discrete receiver for each of said plurality of discrete and individually actuable wellbore tools.

34. A method according to Claim 31, wherein said at least one receiver includes at least one programmable controller for decoding said series of commands and for determining which particular one of said plurality of discrete and individually actuable wellbore tools is to be actuated for each particular command.

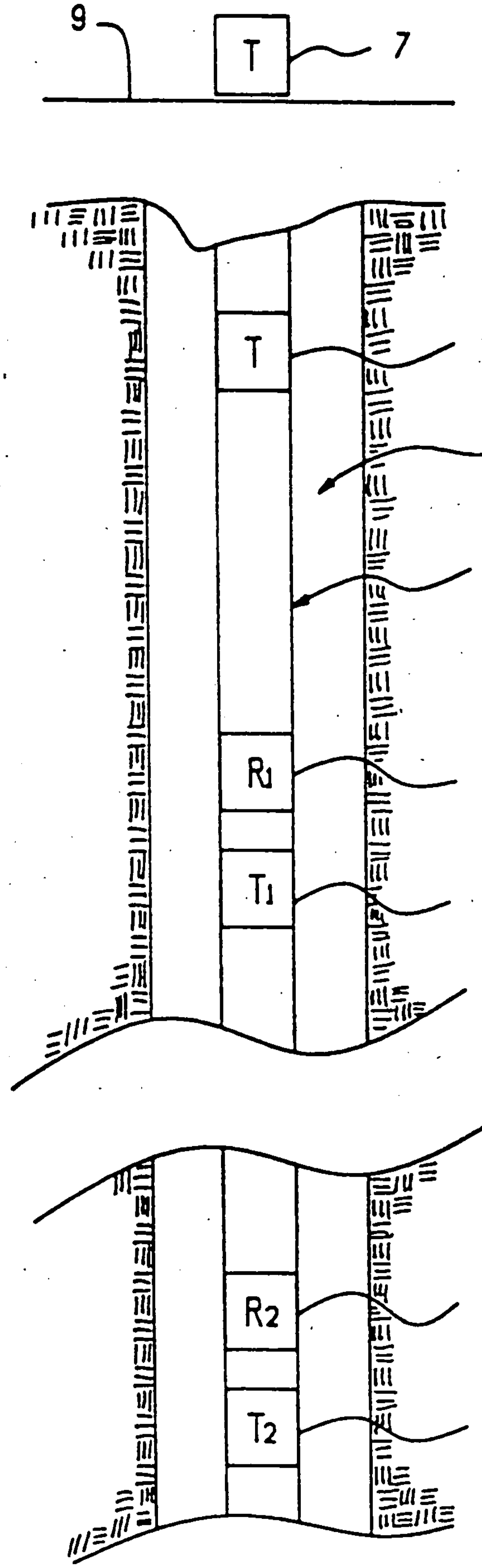

FIG. 1

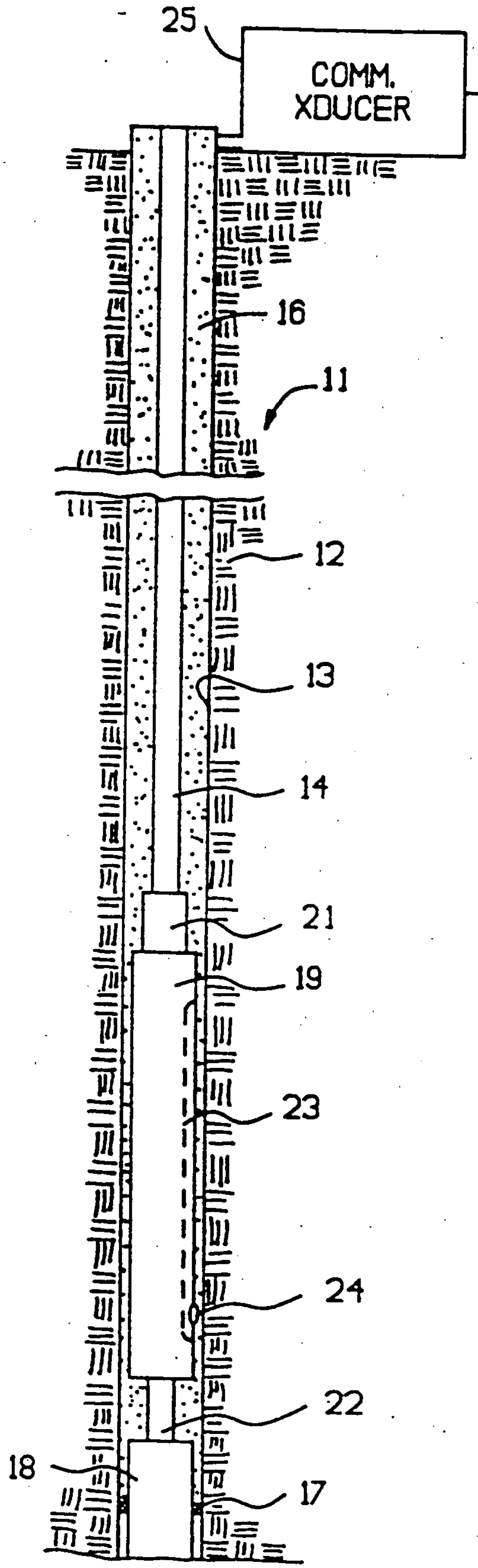
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FIG. 2

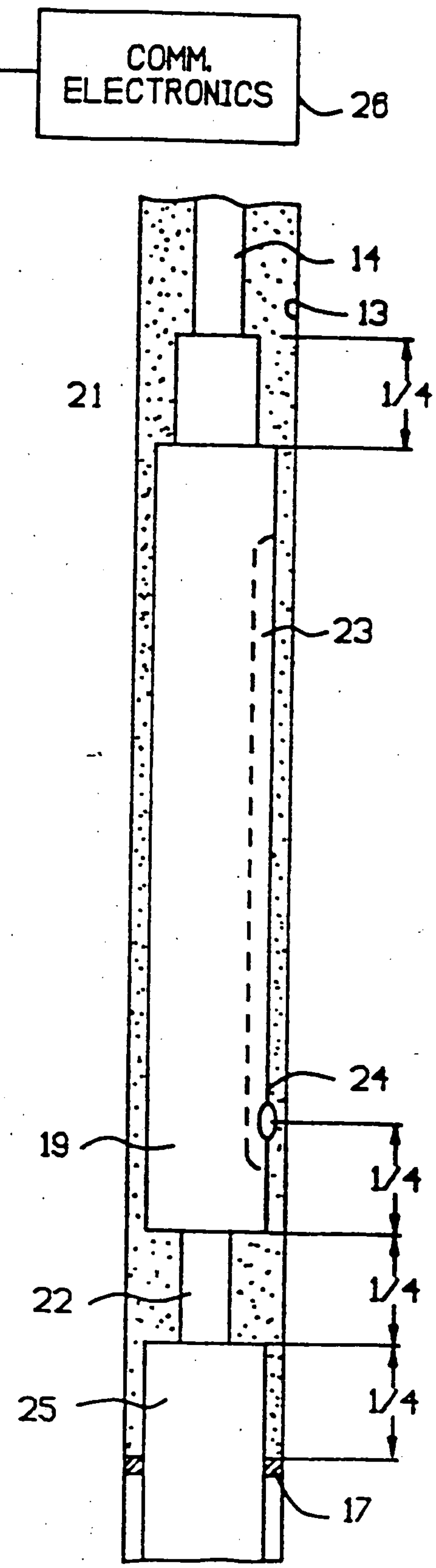
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FIG. 3

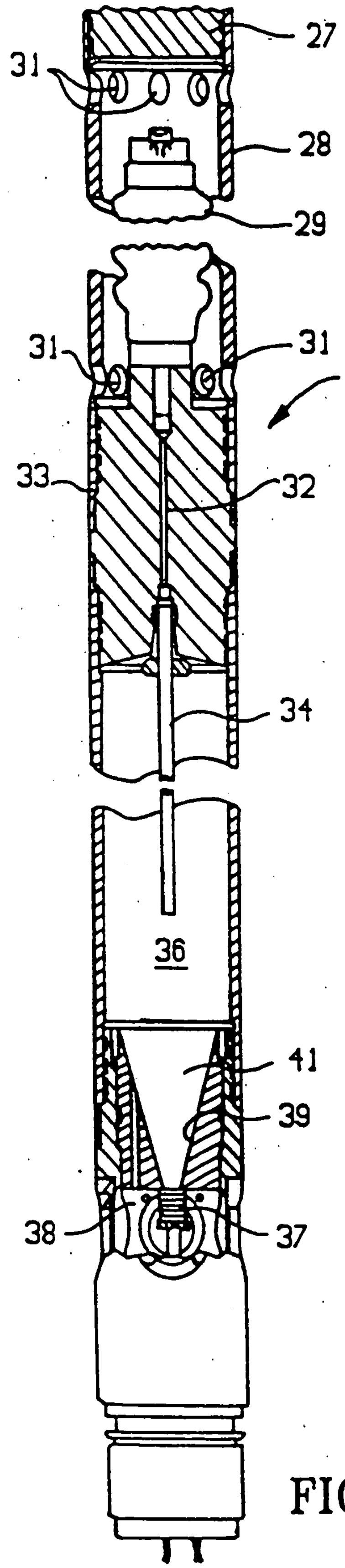


FIG. 4

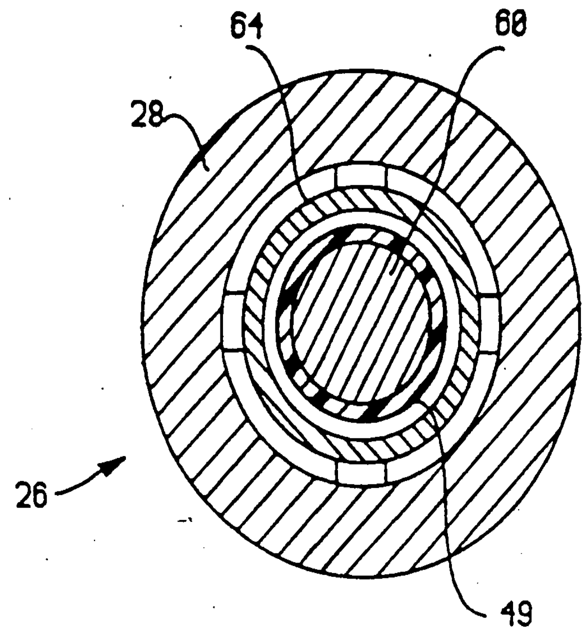


FIG. 6

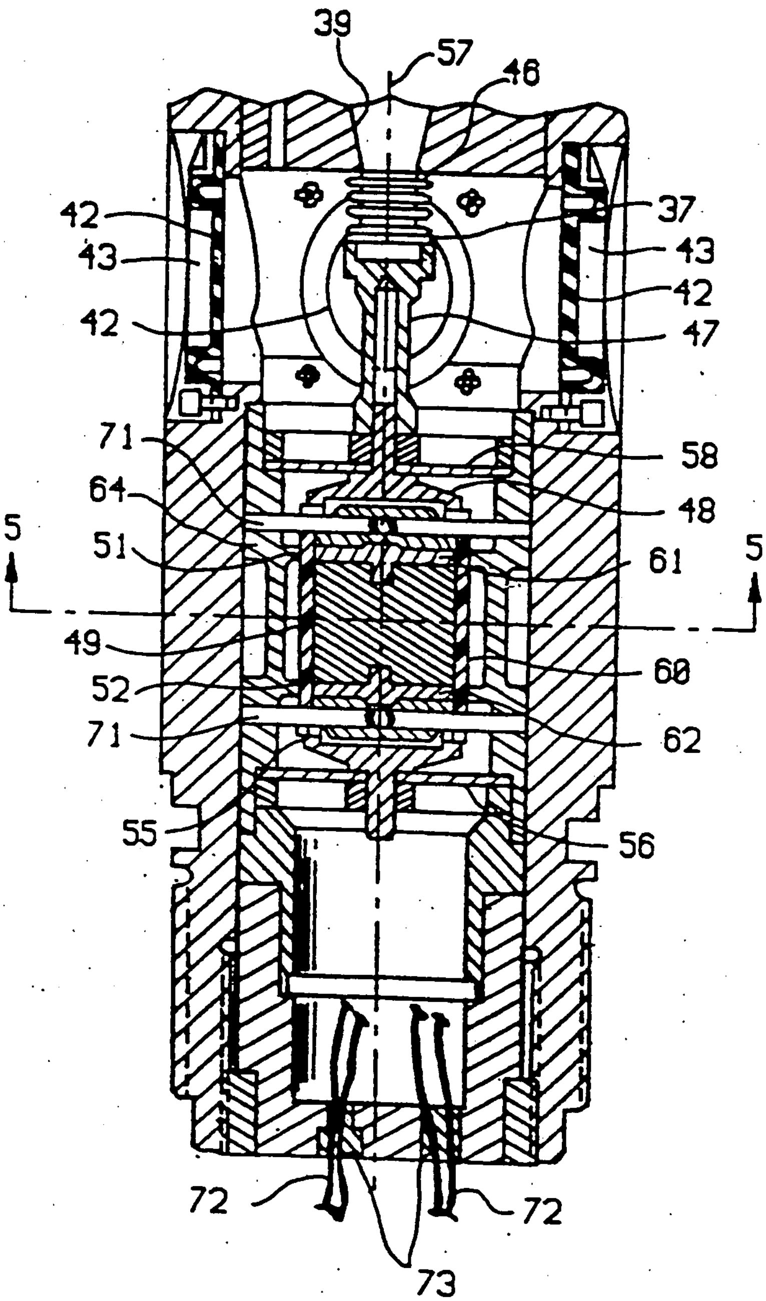

39
57
46
42
43
42
37
43
42
47
71
64
51
5
49
52
71
58
48
61
5
60
62
55
56
72
72
73

FIG. 5

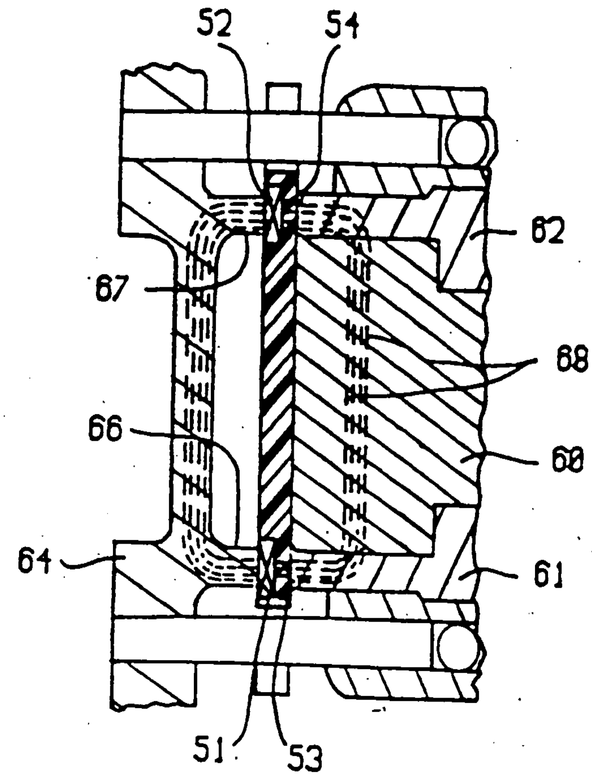


FIG. 7

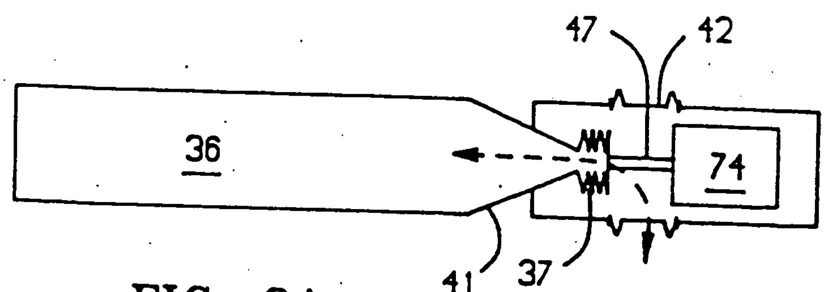


FIG. 8A

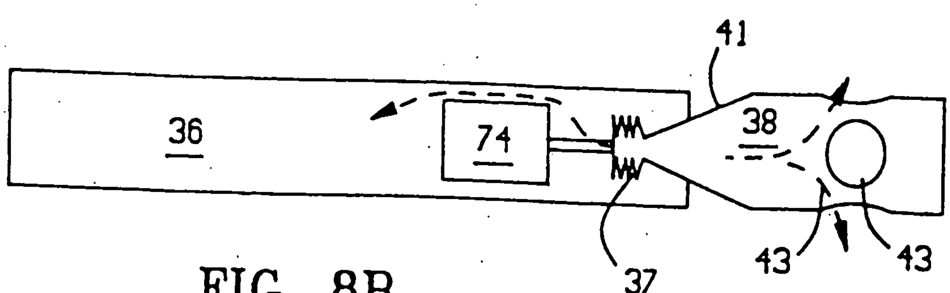


FIG. 8B

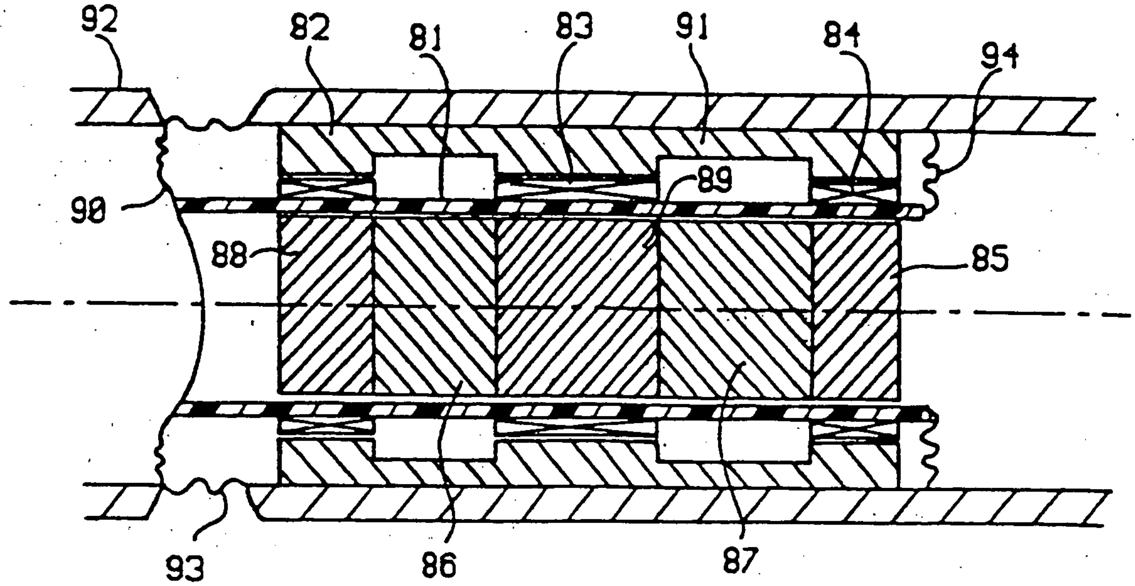


FIG. 9

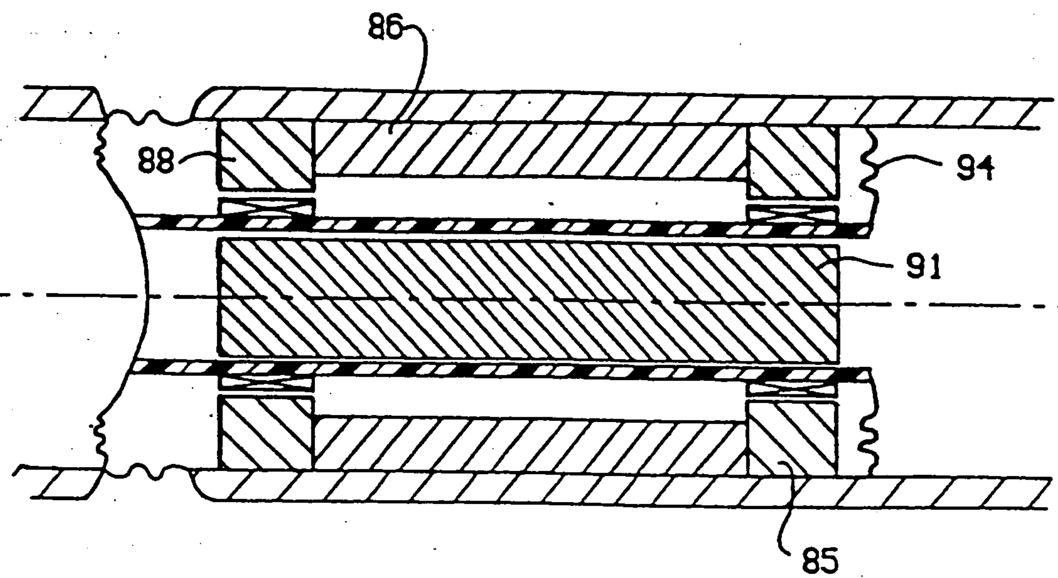


FIG. 10

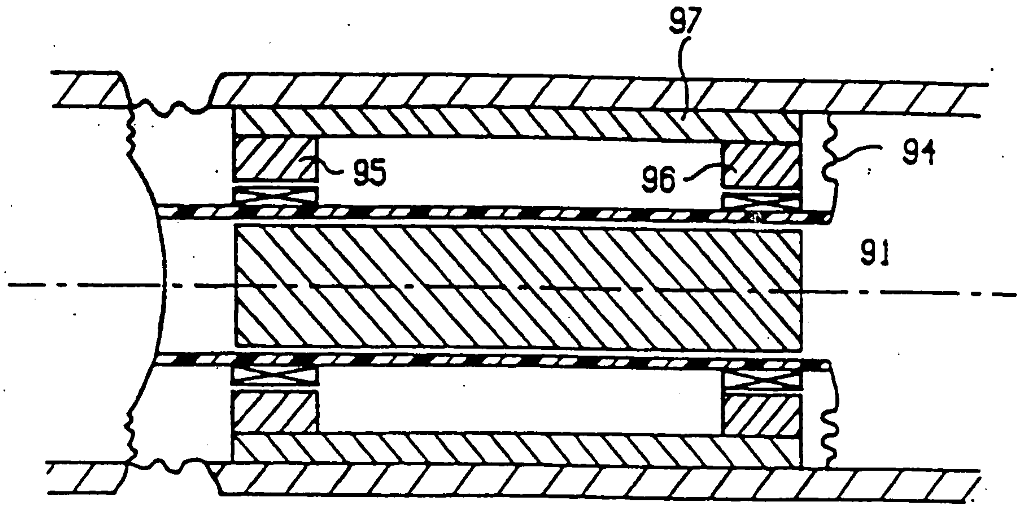


FIG. 11

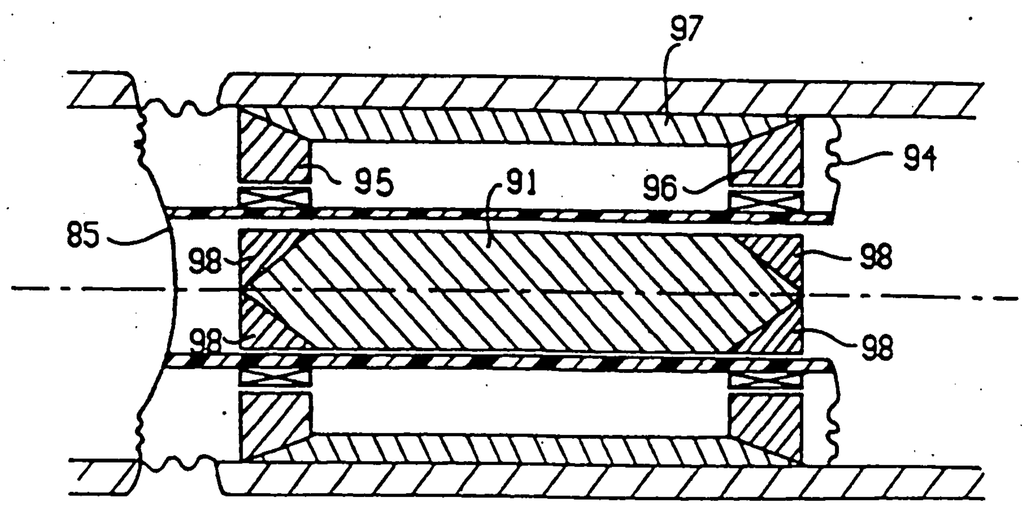


FIG. 12

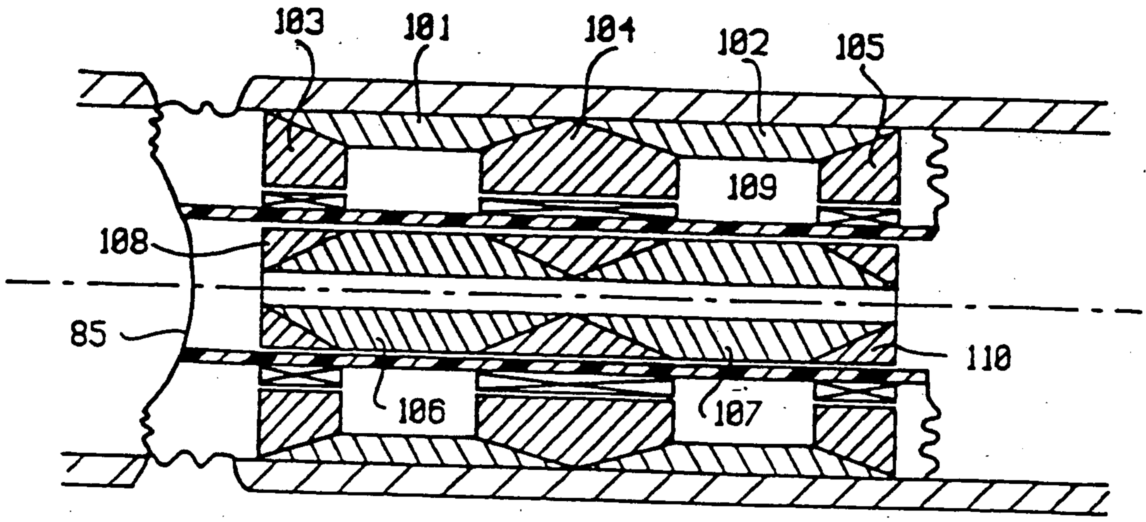


FIG. 13

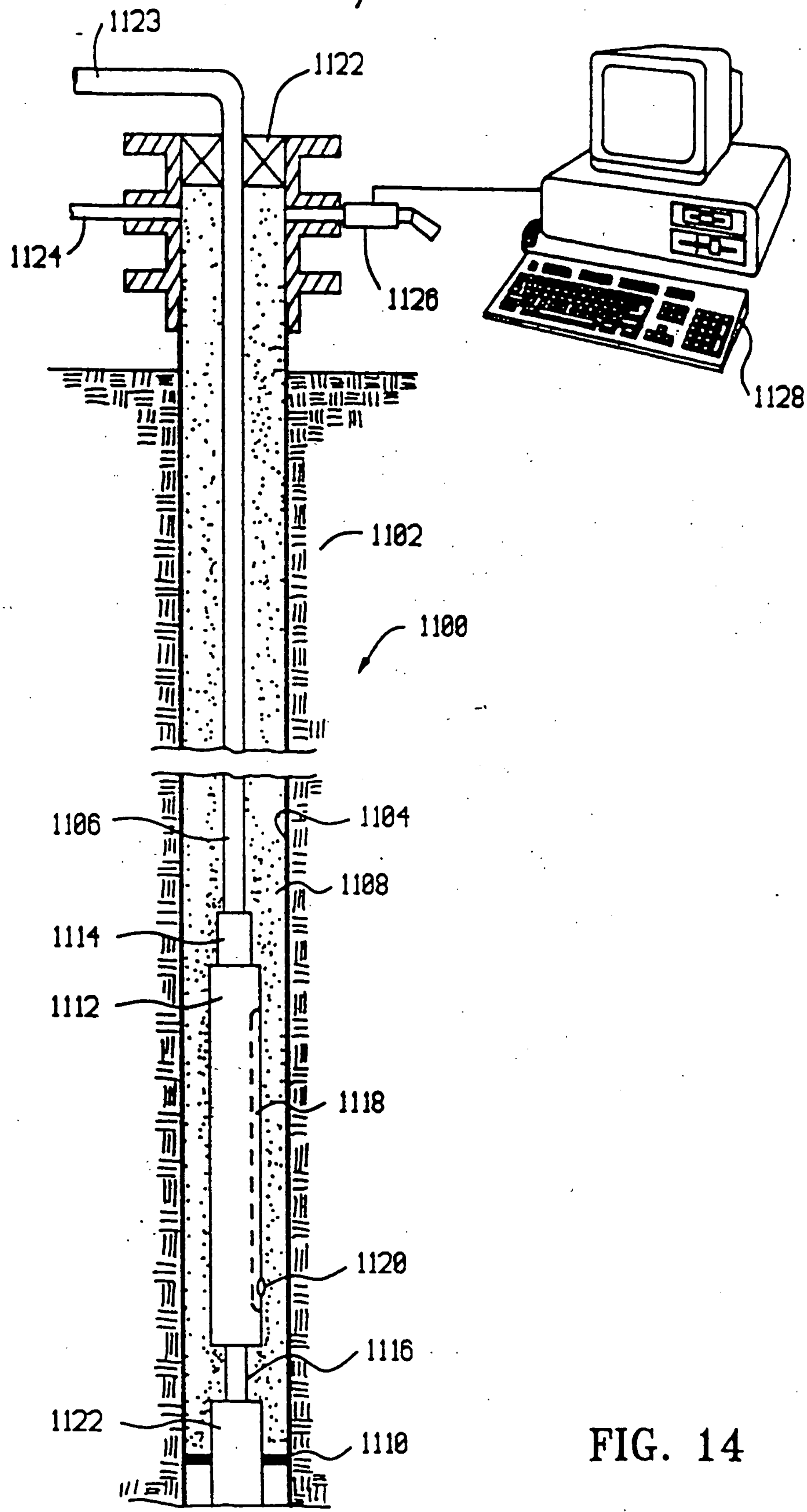

1123
1122
1124
1126
1128
1102
1100
1106
1104
1108
1114
1112
1118
1120
1116
1122
1110

FIG. 14

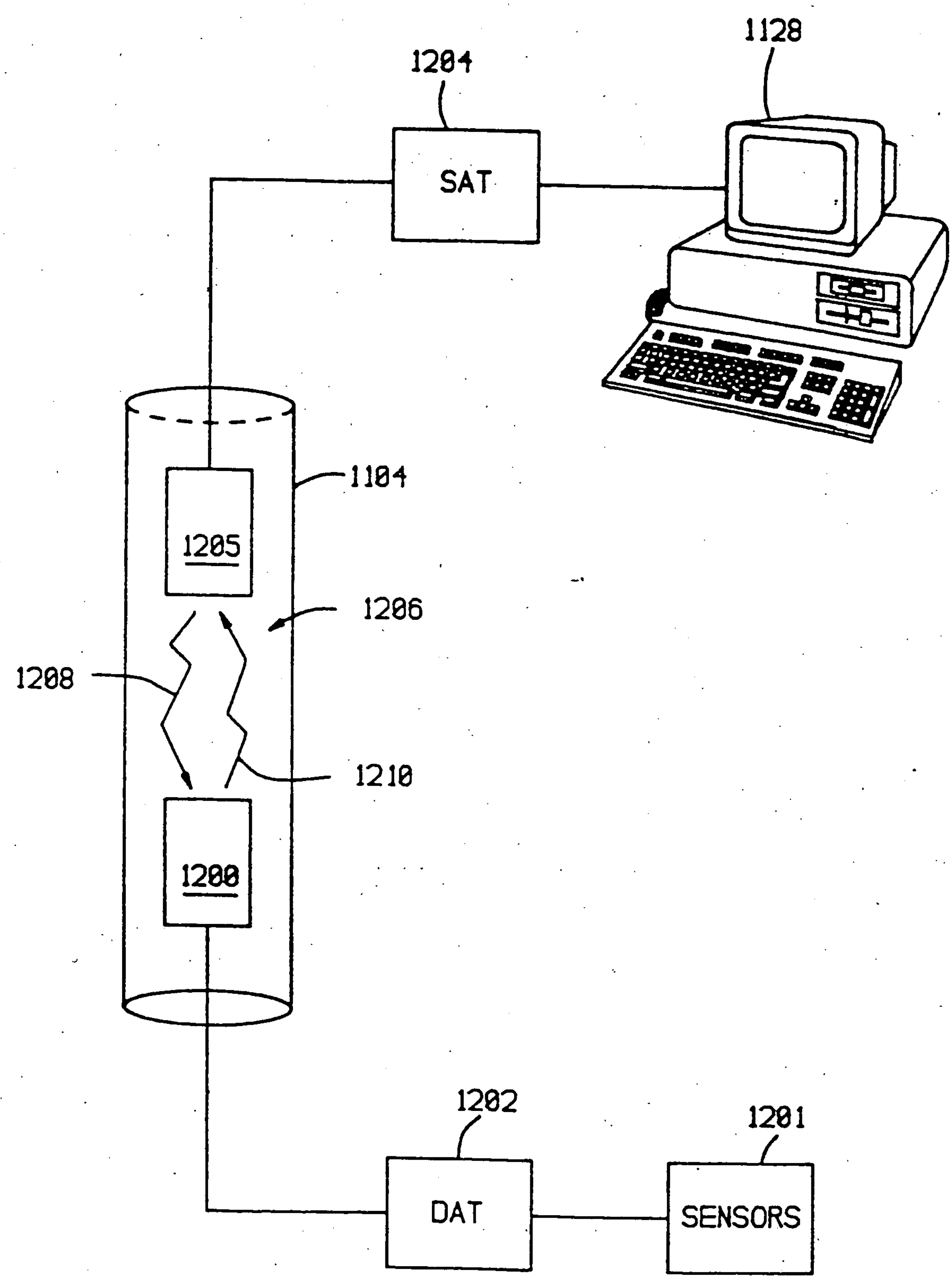

1204
1128
SAT
1104
1205
1206
1208
1210
1200
1202
1201
DAT
SENSORS

FIG. 15

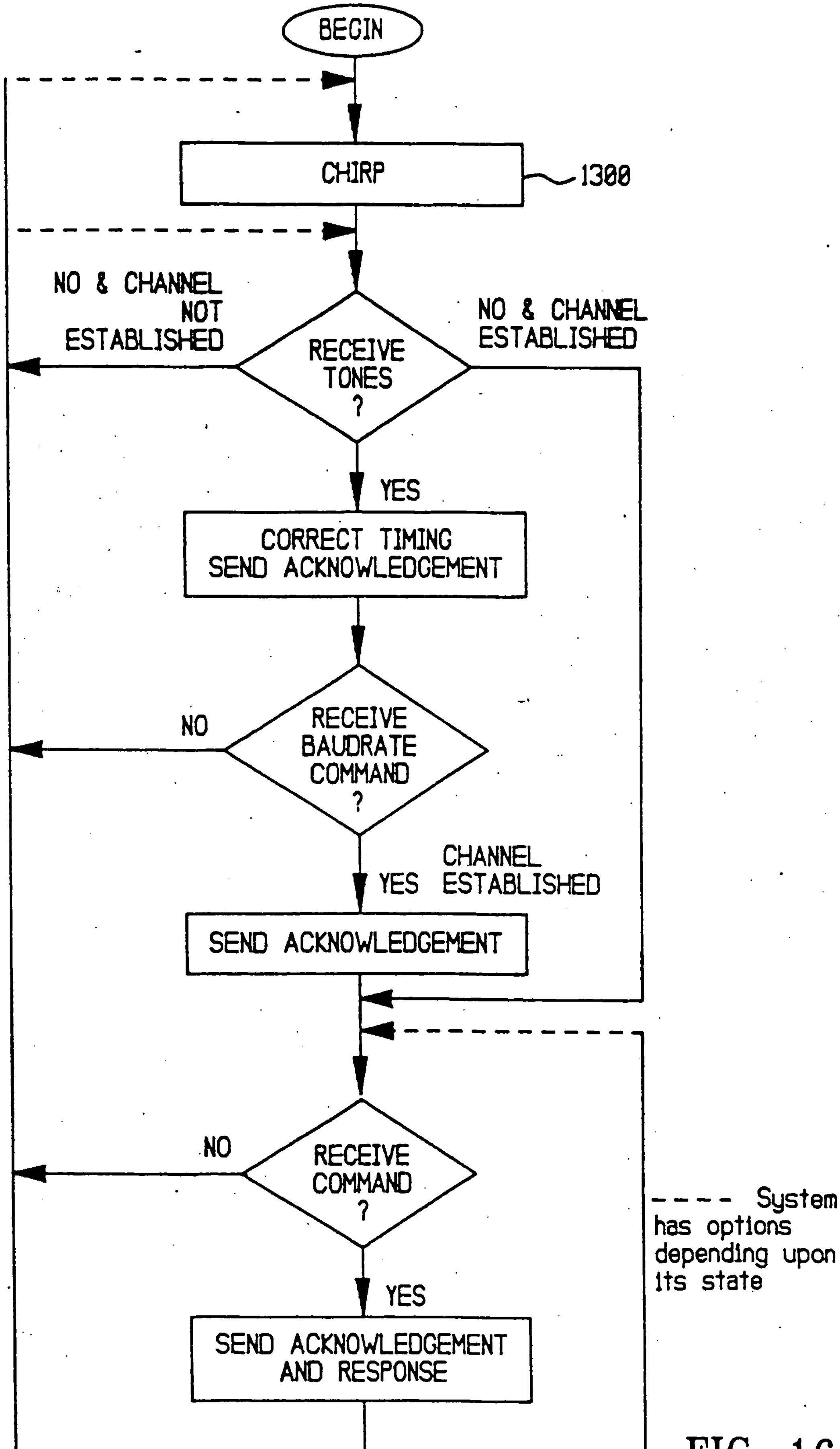

BEGIN
CHIRP
1300
NO & CHANNEL NOT ESTABLISHED
RECEIVE TONES ?
NO & CHANNEL ESTABLISHED
YES
CORRECT TIMING
SEND ACKNOWLEDGEMENT
NO
RECEIVE BAUDRATE COMMAND ?
YES
CHANNEL ESTABLISHED
SEND ACKNOWLEDGEMENT
NO
RECEIVE COMMAND ?
YES
SEND ACKNOWLEDGEMENT AND RESPONSE
---- System has options depending upon its state

FIG. 16

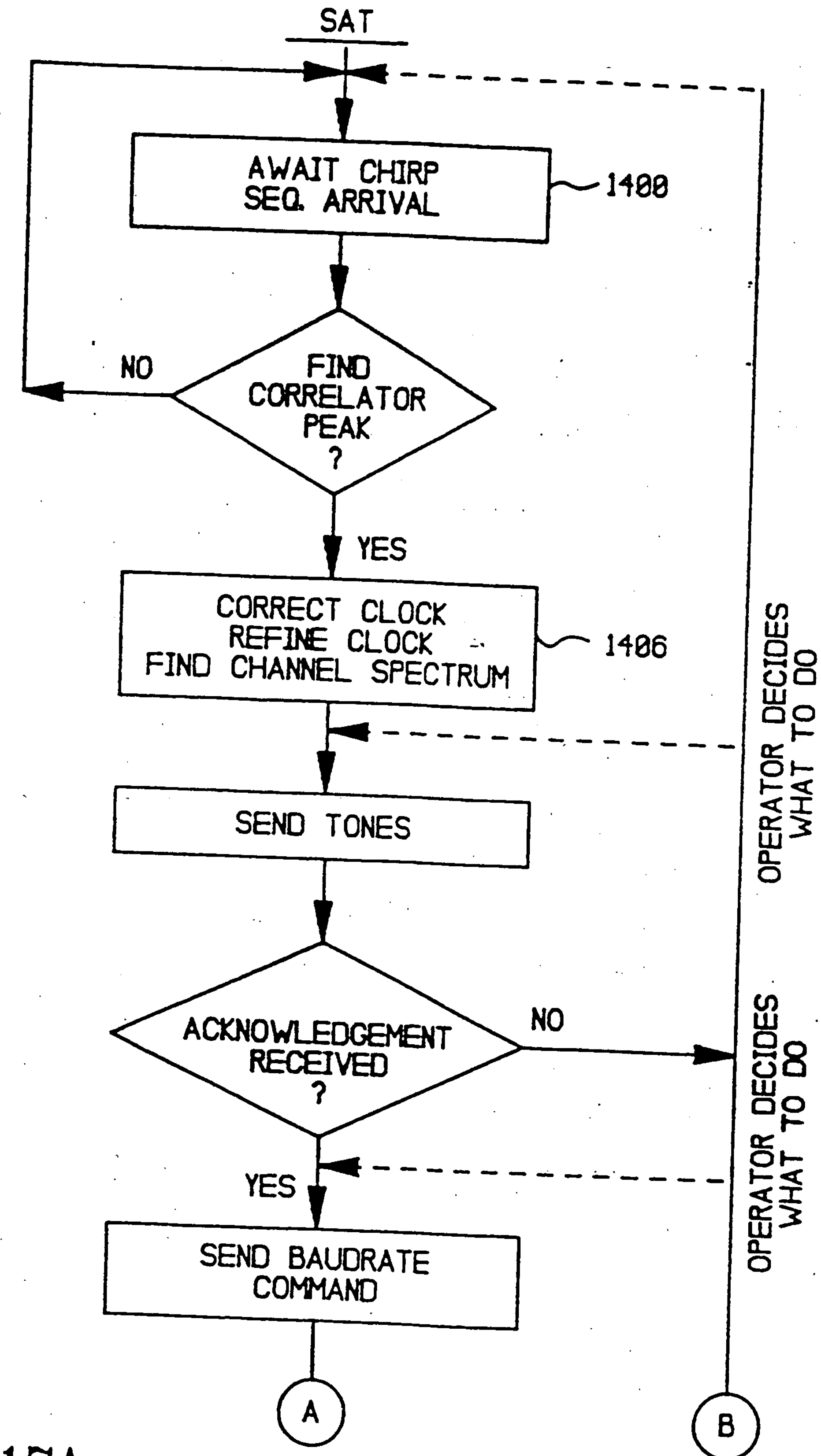

SAT
AWAIT CHIRP SEQ. ARRIVAL
1400
FIND CORRELATOR PEAK ?
NO
YES
CORRECT CLOCK
REFINE CLOCK
FIND CHANNEL SPECTRUM
1406
SEND TONES
ACKNOWLEDGEMENT RECEIVED ?
NO
YES
SEND BAUDRATE COMMAND
A
B
OPERATOR DECIDES WHAT TO DO
OPERATOR DECIDES WHAT TO DO

FIG. 17A

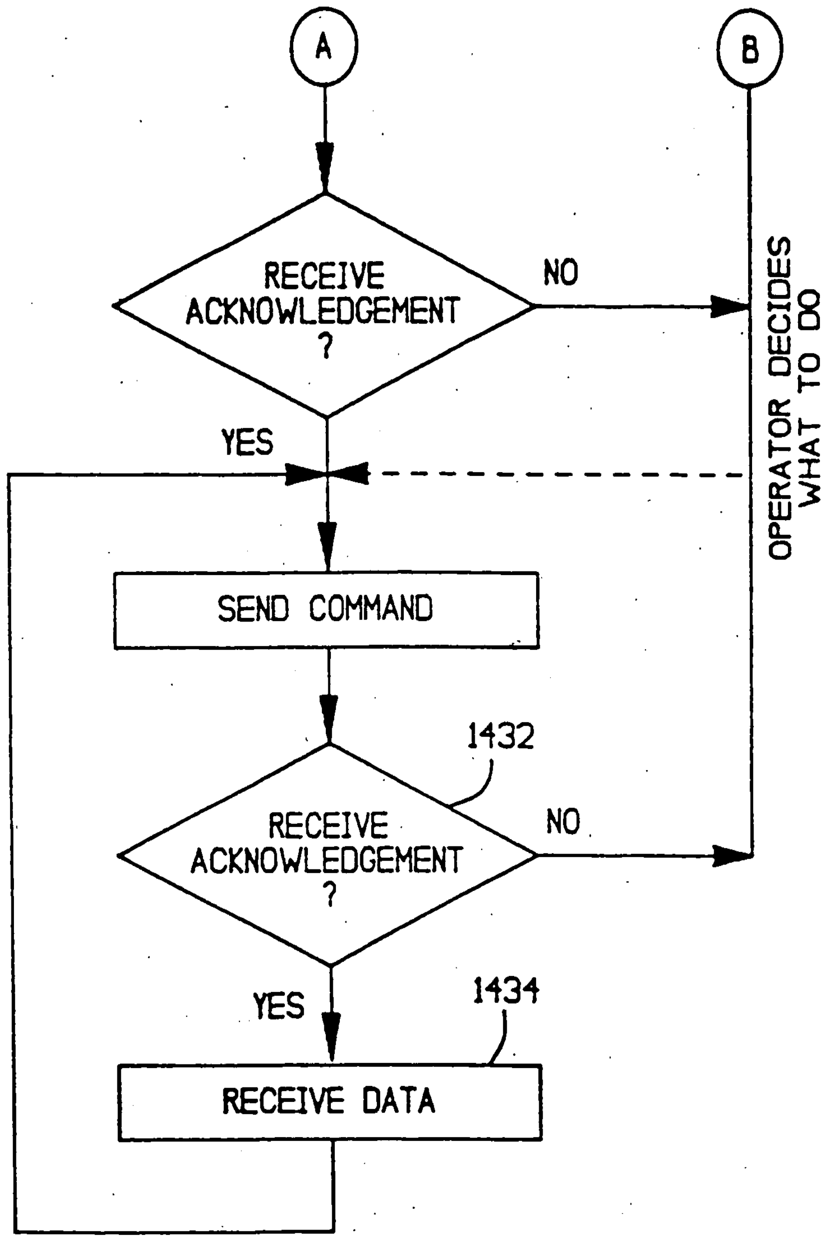

A
B
RECEIVE ACKNOWLEDGEMENT ?
NO
OPERATOR DECIDES WHAT TO DO
YES
SEND COMMAND
1432
RECEIVE ACKNOWLEDGEMENT ?
NO
YES
1434
RECEIVE DATA

FIG. 17B

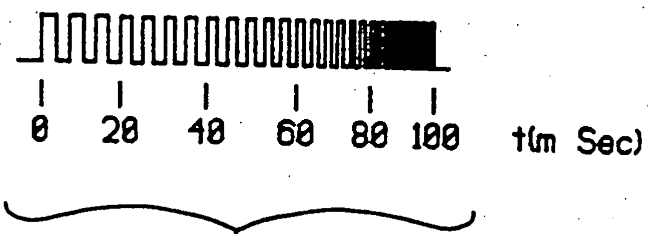


FIG. 18A

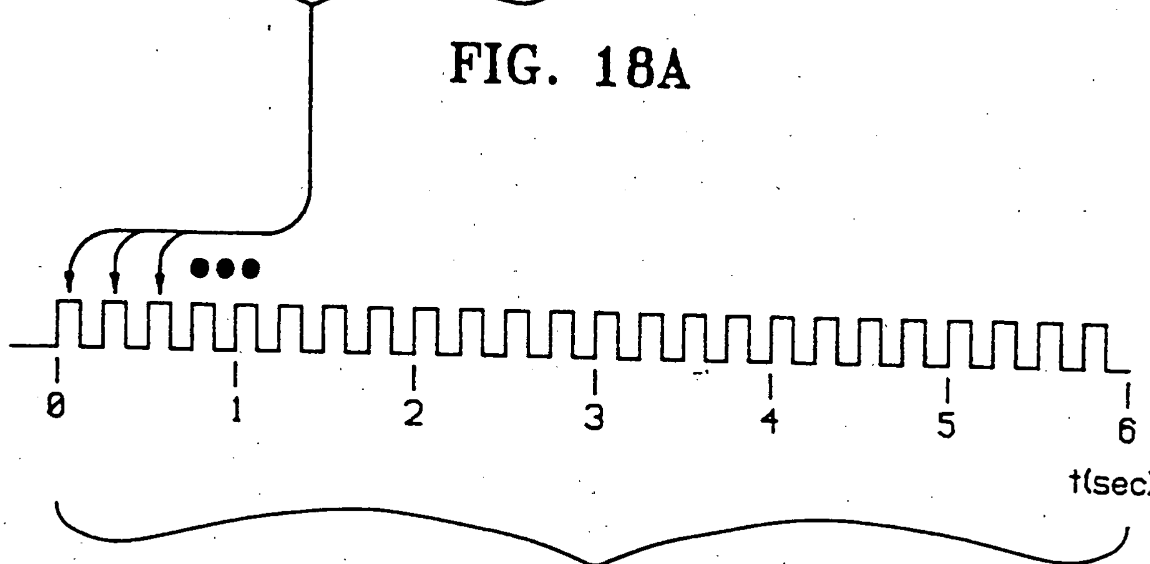


FIG. 18B

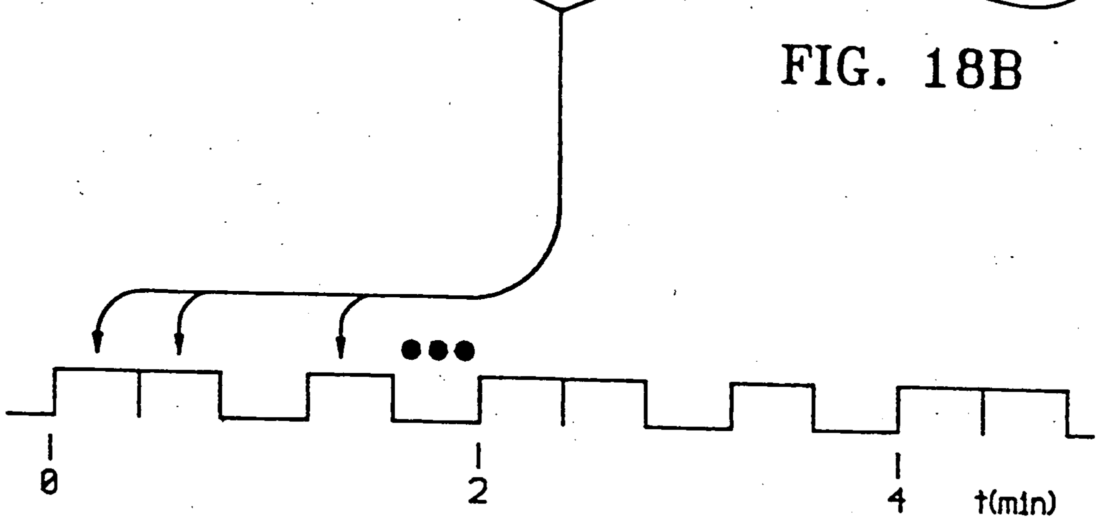


FIG. 18C

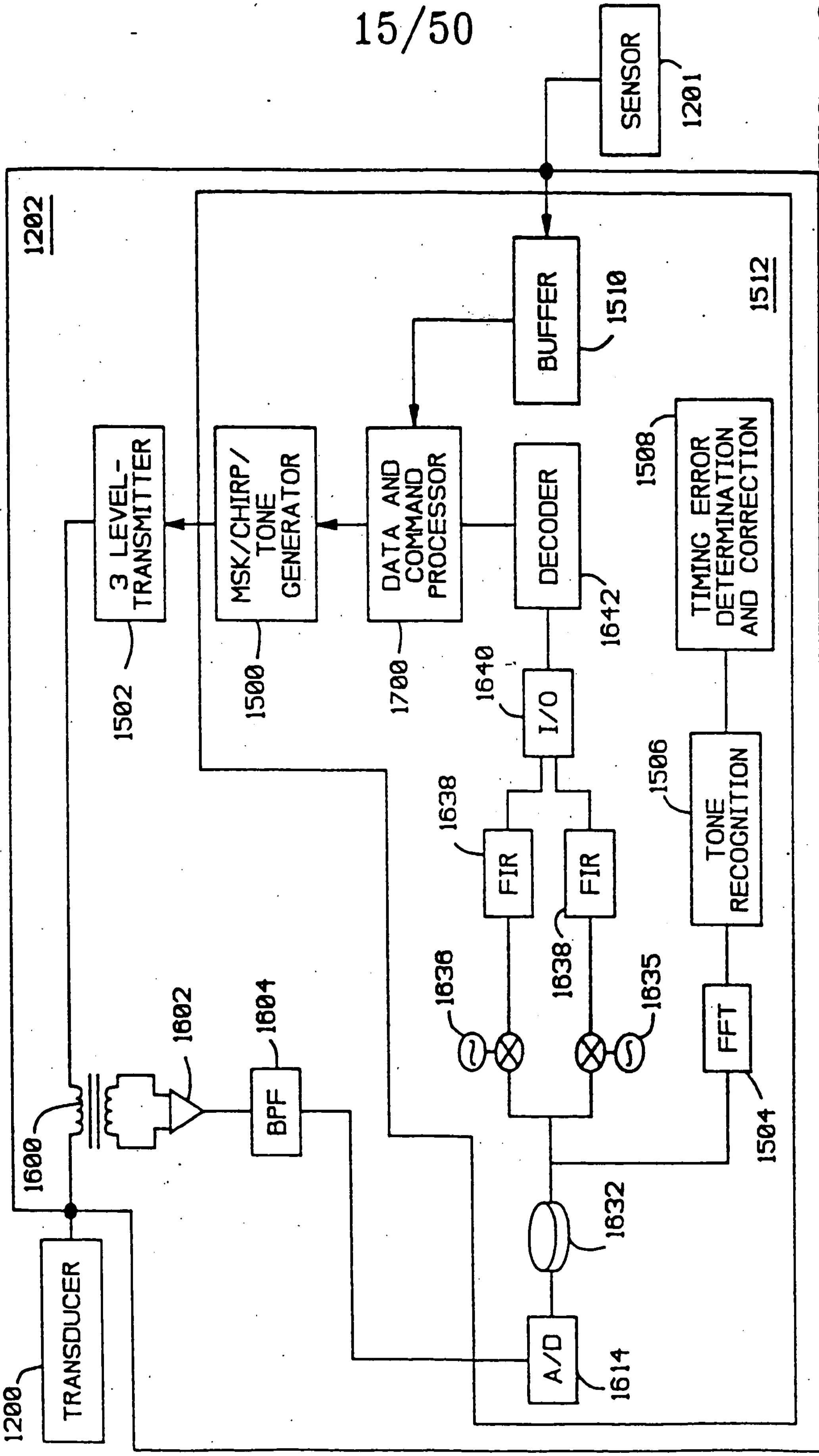

SENSOR
1201
1202
BUFFER
1510
1512
3 LEVEL-TRANSMITTER
MSK/CHIRP/TONE GENERATOR
DATA AND COMMAND PROCESSOR
DECODER
TIMING ERROR DETERMINATION AND CORRECTION
1508
1502
1500
1700
1640
I/O
1642
1638
FIR
FIR
1638
1506
TONE RECOGNITION
1636
1638
1635
1602
1604
BPF
FFT
1600
1504
1632
TRANSDUCER
1200
A/D
1614

FIG. 19

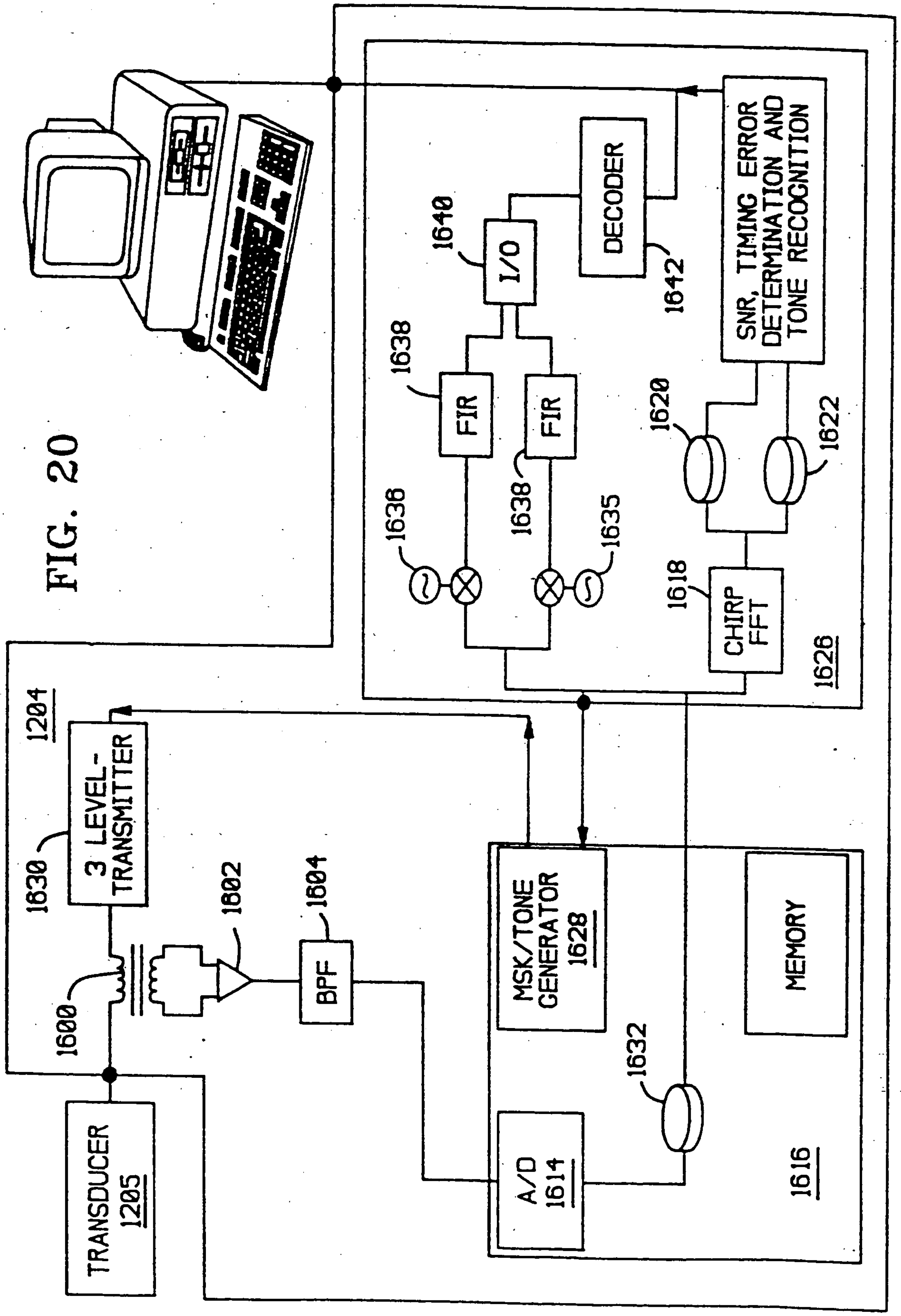

TRANSDUCER
1205
1204
3 LEVEL-
TRANSMITTER
1630
1600
1602
1604
BPF
MSK/TONE
GENERATOR
1628
MEMORY
A/D
1614
1632
1616
SNR, TIMING ERROR
DETERMINATION AND
TONE RECOGNITION
DECODER
1642
I/O
1640
FIR
FIR
1638
1638
1636
1635
1620
1622
CHIRP
FFT
1618
1626

FIG. 20

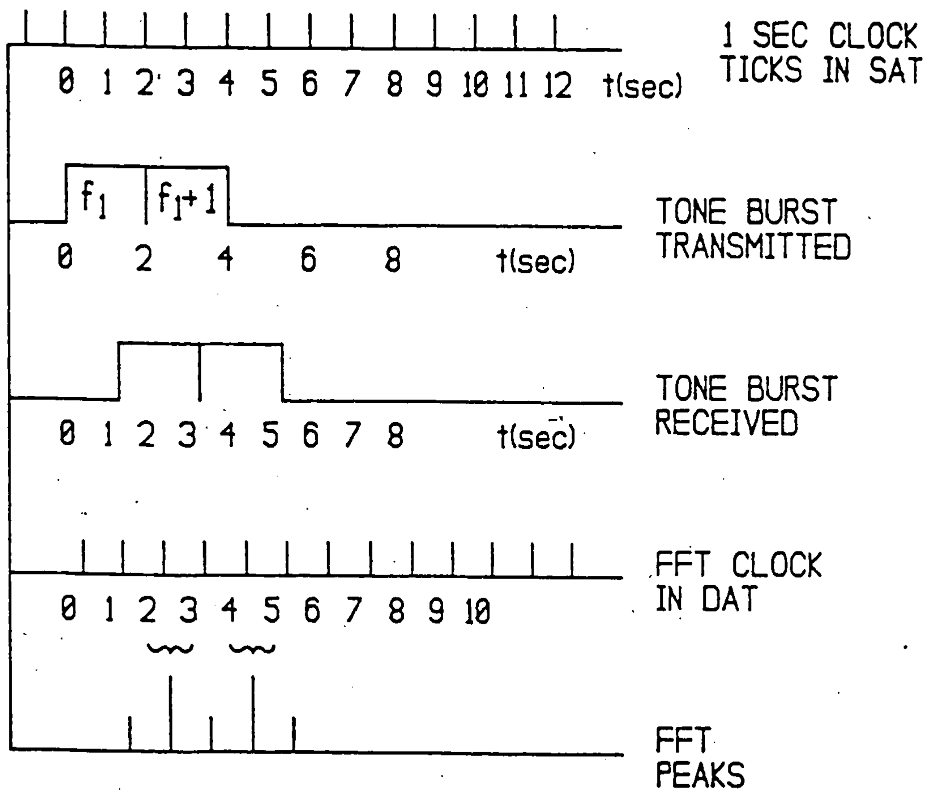

0 1 2 3 4 5 6 7 8 9 10 11 12 t(sec)
1 SEC CLOCK TICKS IN SAT
f_1
f_1+1
0 2 4 6 8 t(sec)
TONE BURST TRANSMITTED
0 1 2 3 4 5 6 7 8 t(sec)
TONE BURST RECEIVED
0 1 2 3 4 5 6 7 8 9 10
FFT CLOCK IN DAT
FFT PEAKS

FIG. 21

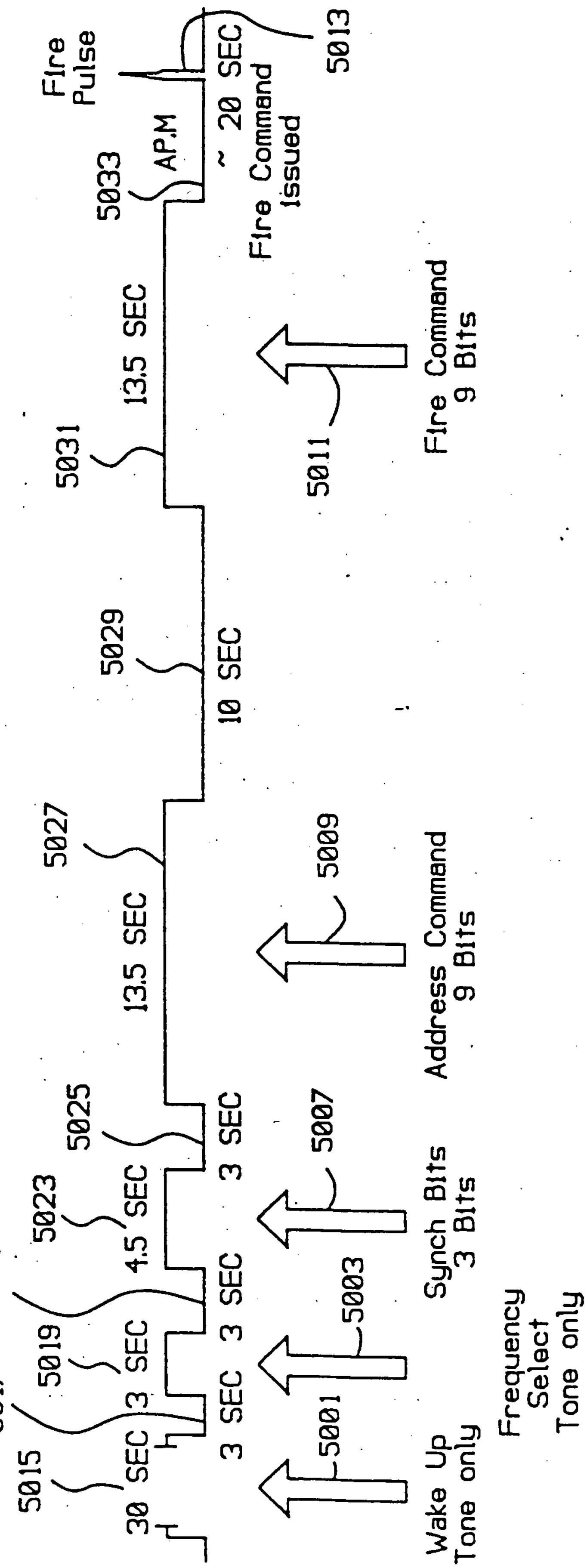

30 SEC
5015
3 SEC
5017
3 SEC
5019
3 SEC
5021
3 SEC
4.5 SEC
5023
3 SEC
5025
13.5 SEC
5027
10 SEC
5029
13.5 SEC
5031
5033
AP.M
~ 20 SEC
Fire Pulse
5013
Fire Command Issued
Wake Up Tone only
5001
Frequency Select Tone only
5003
Synch Bits 3 Bits
5007
Address Command 9 Bits
5009
Fire Command 9 Bits
5011

FIG. 22

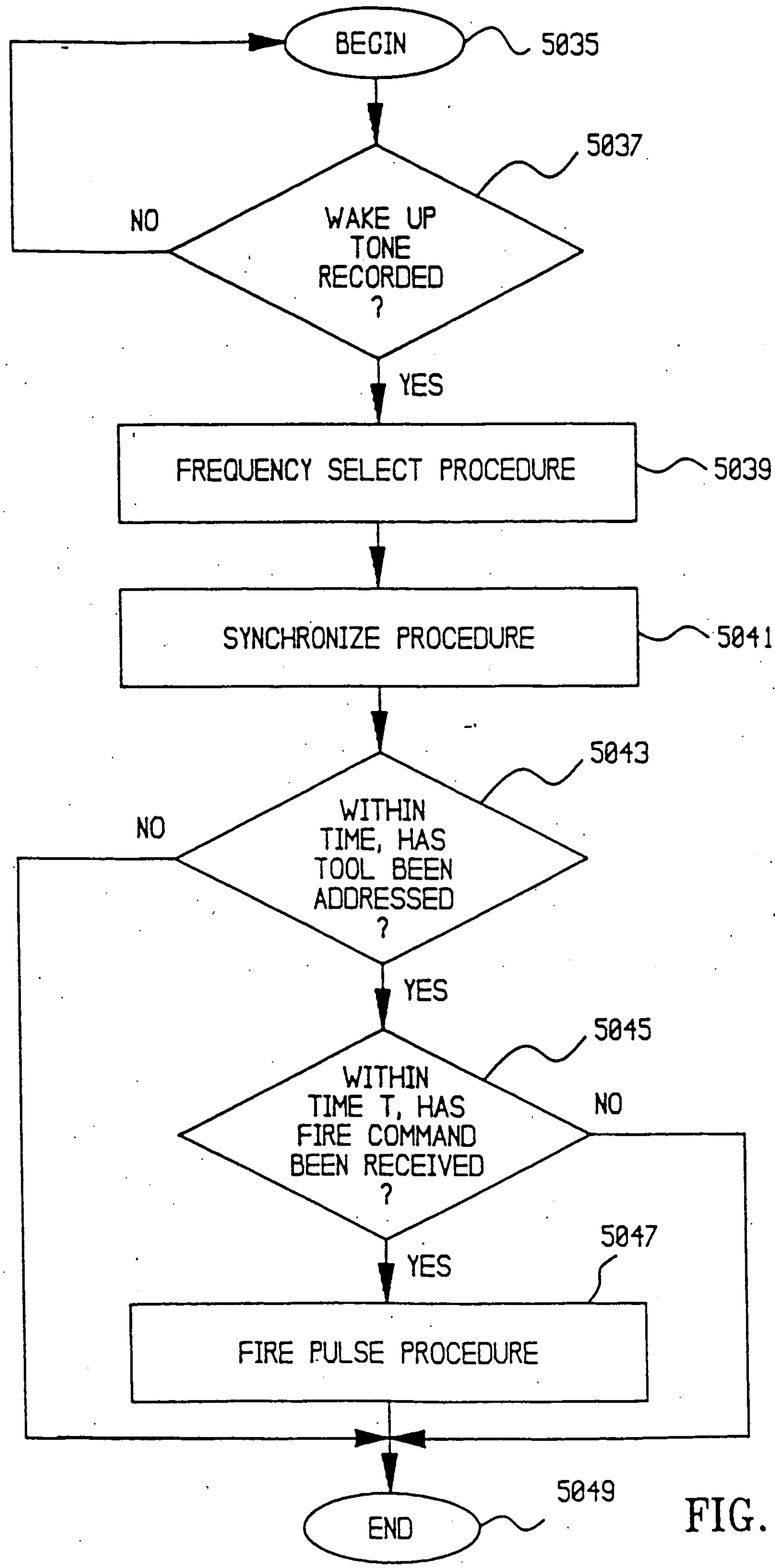
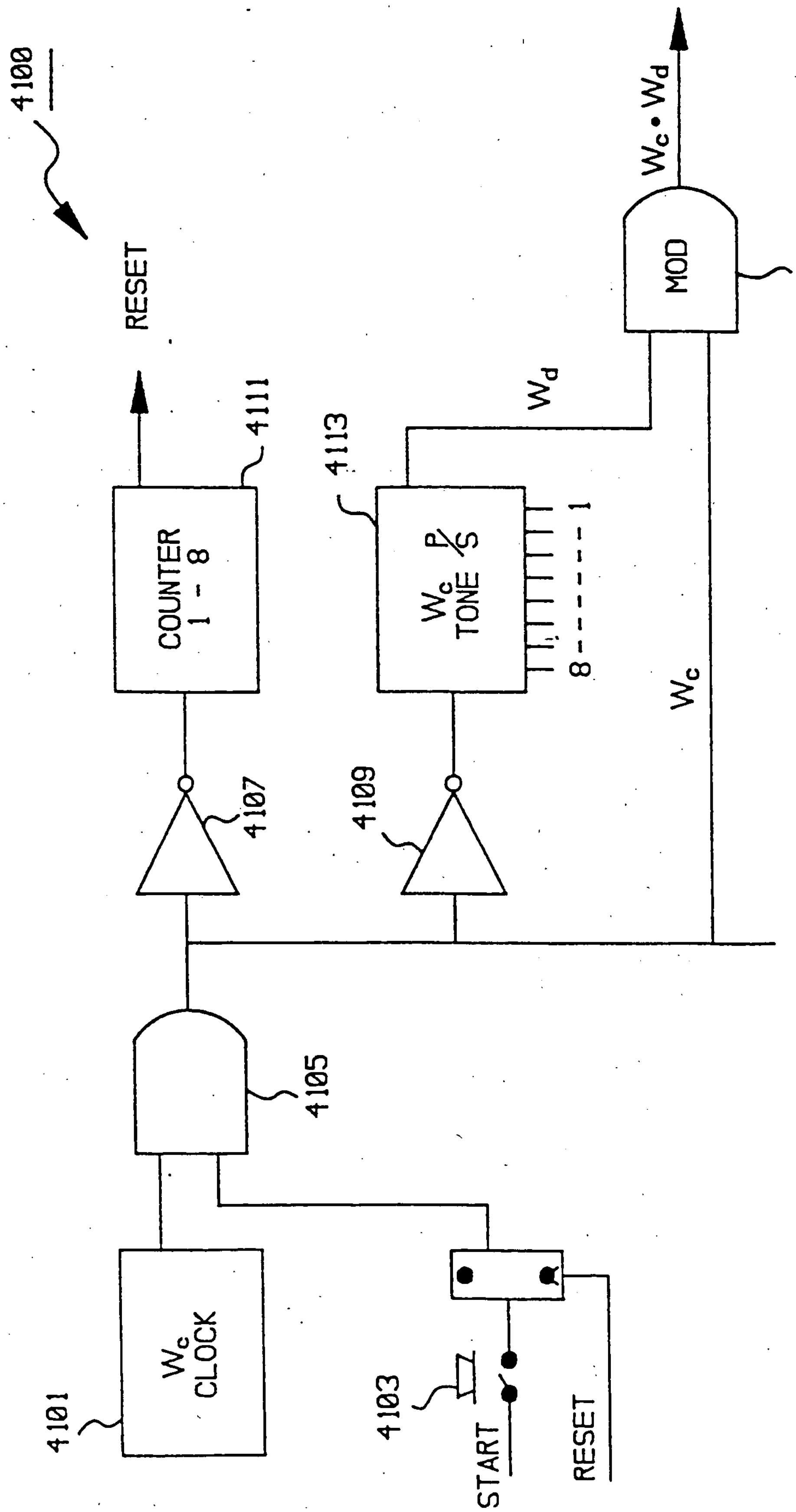

BEGIN
5035
WAKE UP TONE RECORDED ?
5037
NO
YES
FREQUENCY SELECT PROCEDURE
5039
SYNCHRONIZE PROCEDURE
5041
WITHIN TIME, HAS TOOL BEEN ADDRESSED ?
5043
NO
YES
WITHIN TIME T, HAS FIRE COMMAND BEEN RECEIVED ?
5045
NO
YES
5047
FIRE PULSE PROCEDURE
END
5049

FIG. 23



4100
RESET
4111
COUNTER
1 - 8
4113
W_c
TONE P/S
8 - - - - - - 1
W_d
MOD
4115
$W_c \cdot W_d$
W_c
4107
4109
4105
W_c
CLOCK
4101
4103
START
RESET

FIG. 24

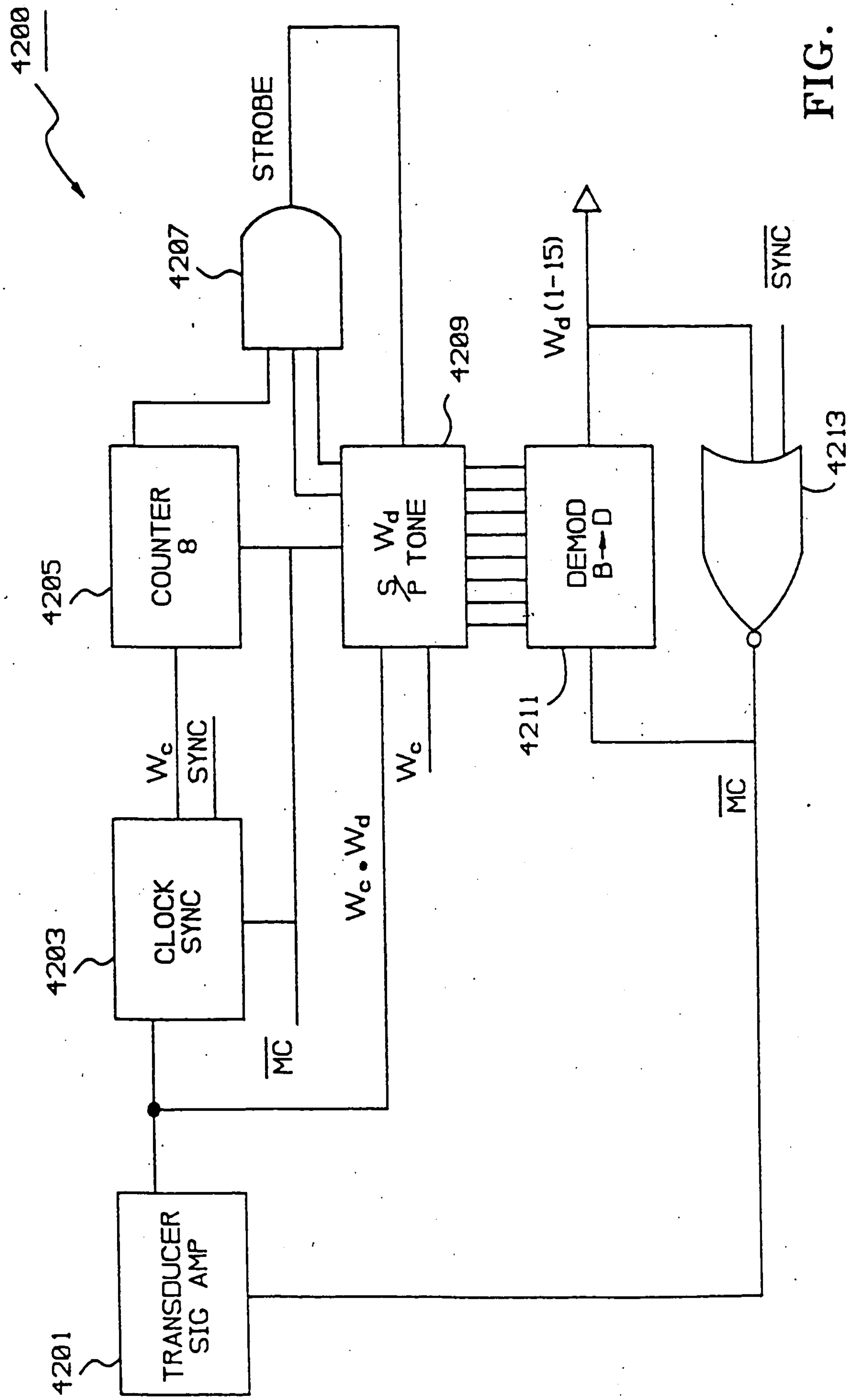

4200
STROBE
4207
4209
Wd(1-15)
SYNC
4213
COUNTER
8
4205
S/P Wd TONE
DEMOD
B→D
4211
Wc
SYNC
CLOCK
SYNC
4203
Wc • Wd
Wc
MC
MC
TRANSDUCER
SIG AMP
4201

FIG. 25

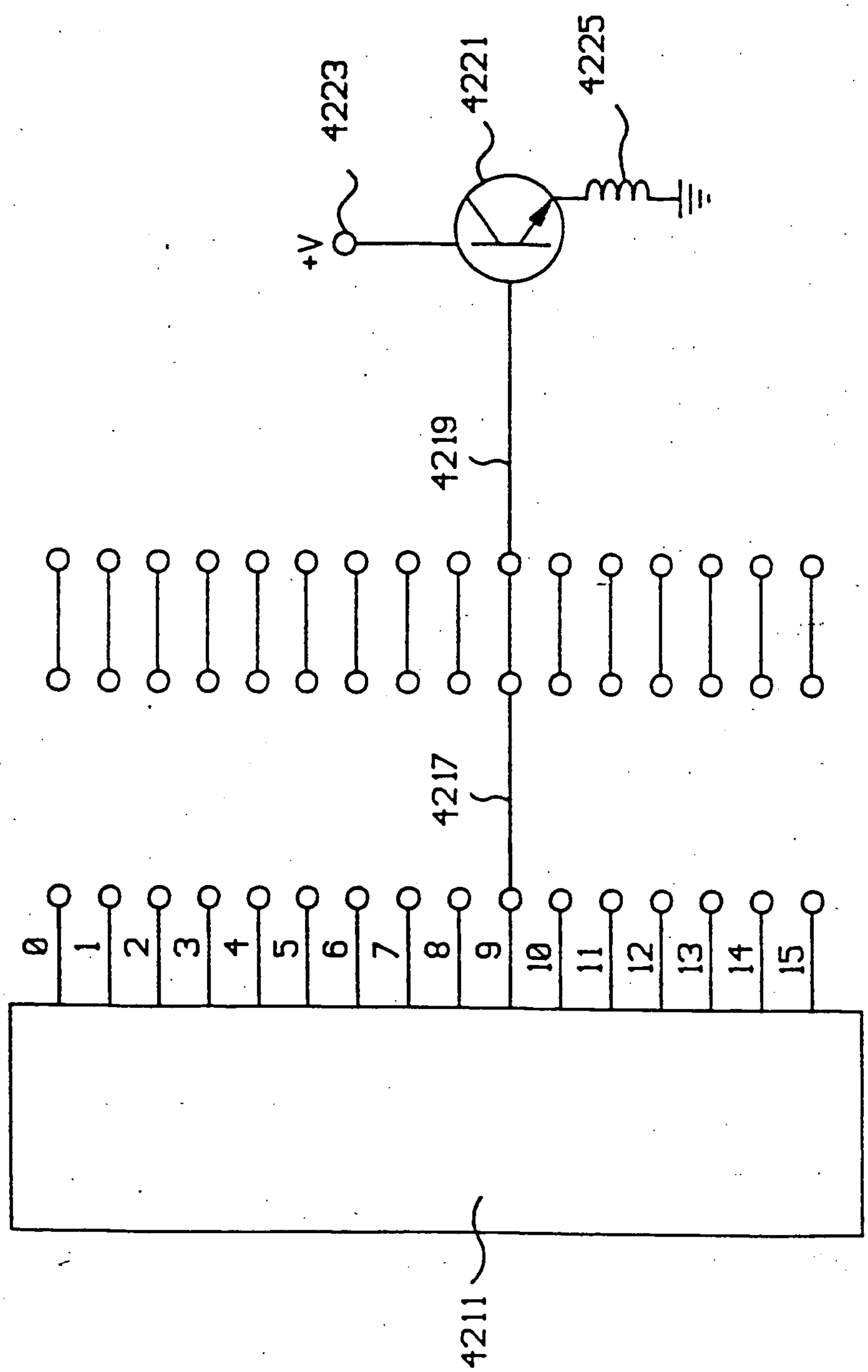


FIG. 26

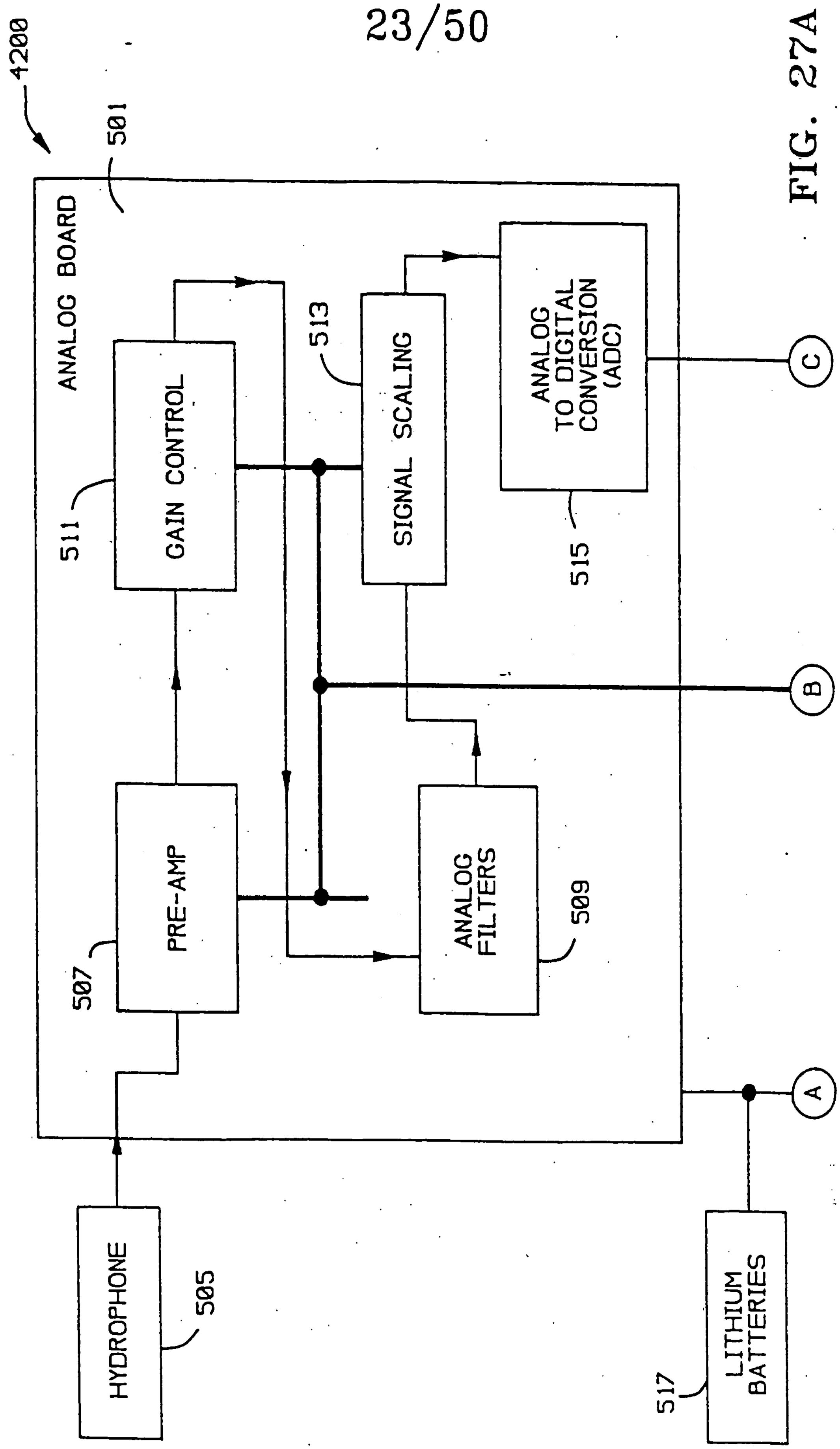
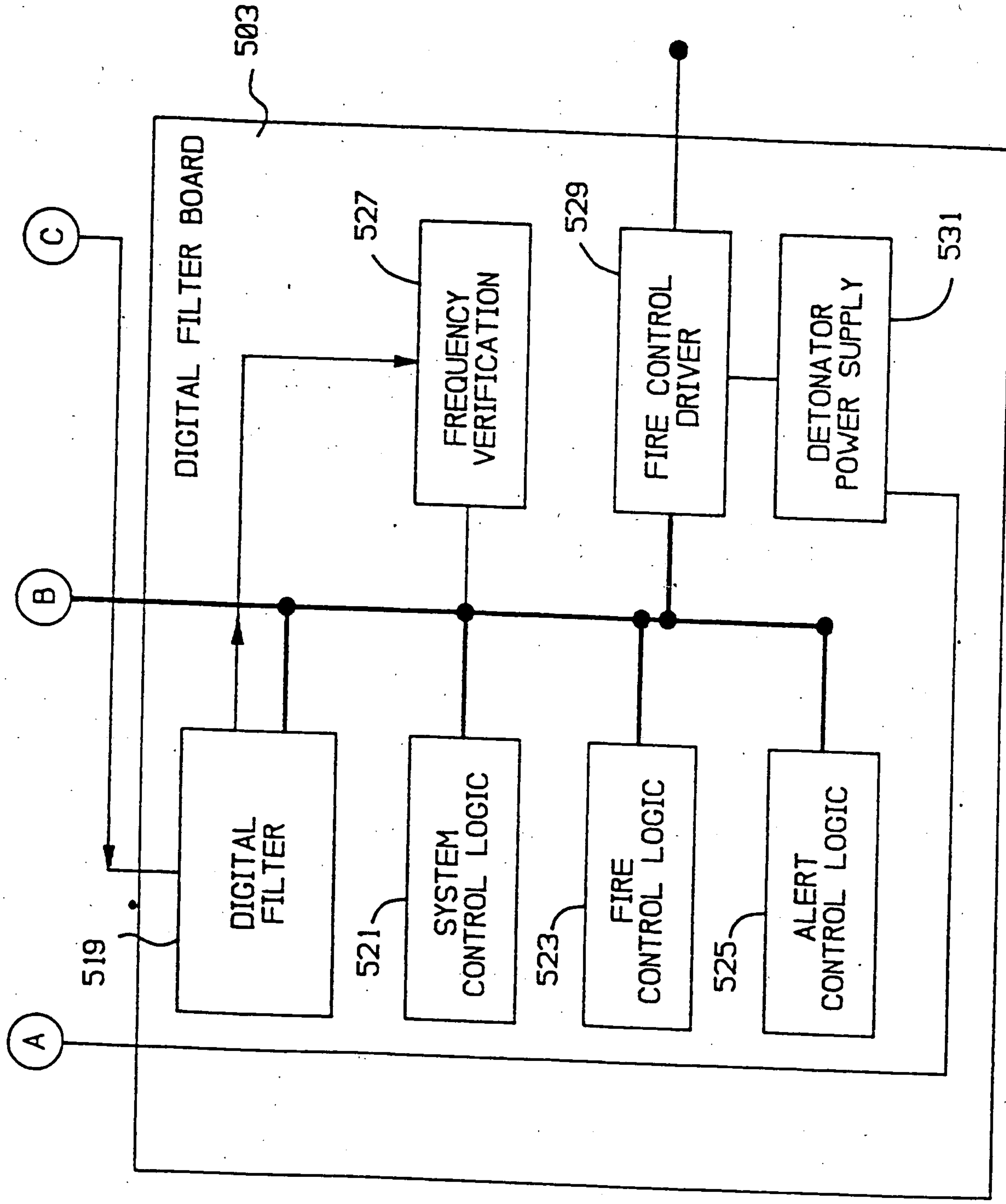
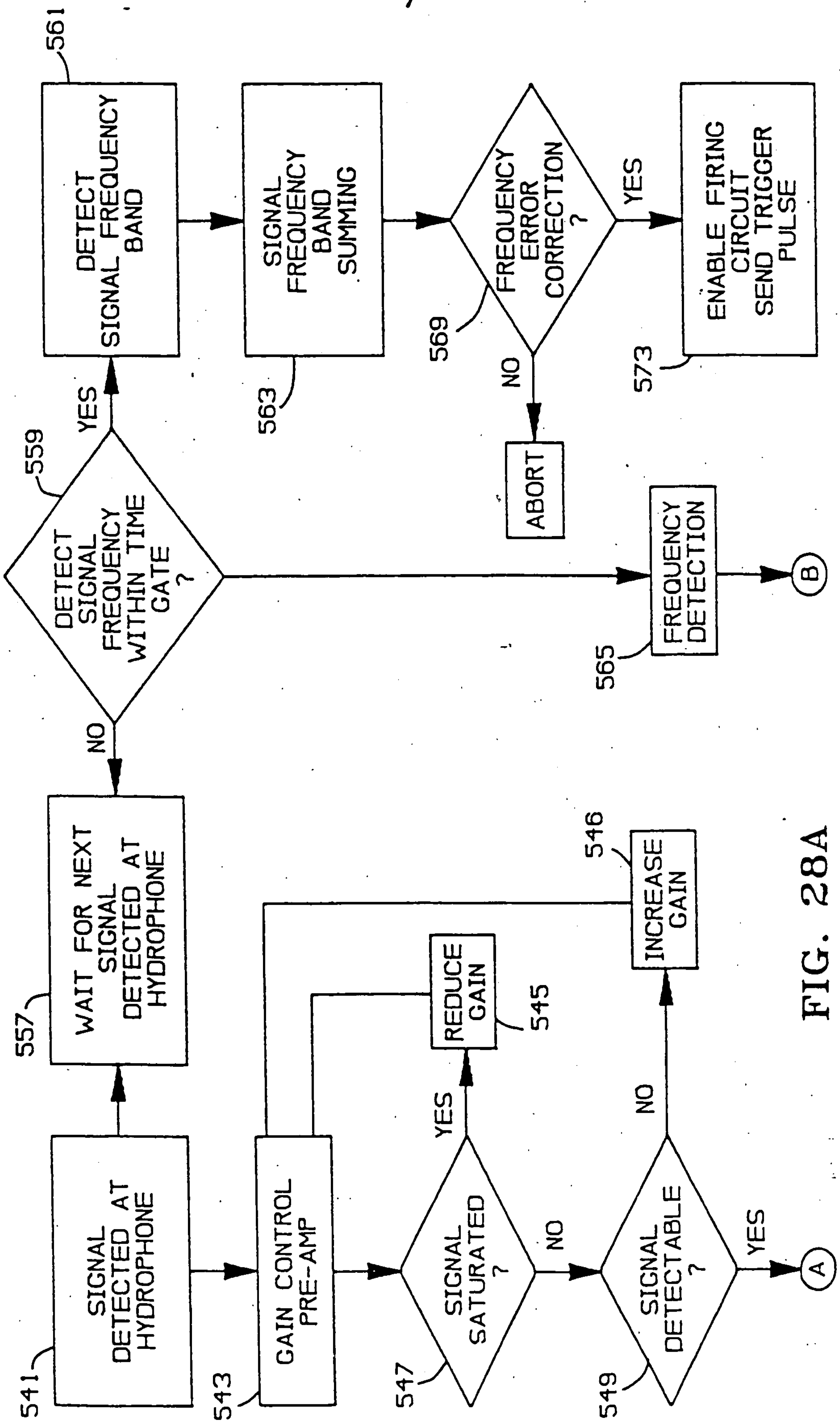

4200
501
ANALOG BOARD
GAIN CONTROL
511
SIGNAL SCALING
513
ANALOG TO DIGITAL CONVERSION (ADC)
515
PRE-AMP
507
ANALOG FILTERS
509
A
B
C
HYDROPHONE
505
LITHIUM BATTERIES
517

FIG. 27A

FIG. 27B


503
DIGITAL FILTER BOARD
527
FREQUENCY VERIFICATION
529
FIRE CONTROL DRIVER
531
DETONATOR POWER SUPPLY
C
B
A
DIGITAL FILTER
519
SYSTEM CONTROL LOGIC
521
FIRE CONTROL LOGIC
523
ALERT CONTROL LOGIC
525



SIGNAL DETECTED AT HYDROPHONE
541
GAIN CONTROL PRE-AMP
543
SIGNAL SATURATED ?
547
YES
NO
REDUCE GAIN
545
SIGNAL DETECTABLE ?
549
YES
NO
A
INCREASE GAIN
546
WAIT FOR NEXT SIGNAL DETECTED AT HYDROPHONE
557
DETECT SIGNAL FREQUENCY WITHIN TIME GATE ?
559
YES
NO
FREQUENCY DETECTION
565
B
DETECT SIGNAL FREQUENCY BAND
561
SIGNAL FREQUENCY BAND SUMMING
563
FREQUENCY ERROR CORRECTION ?
569
YES
NO
ABORT
ENABLE FIRING CIRCUIT SEND TRIGGER PULSE
573

FIG. 28A

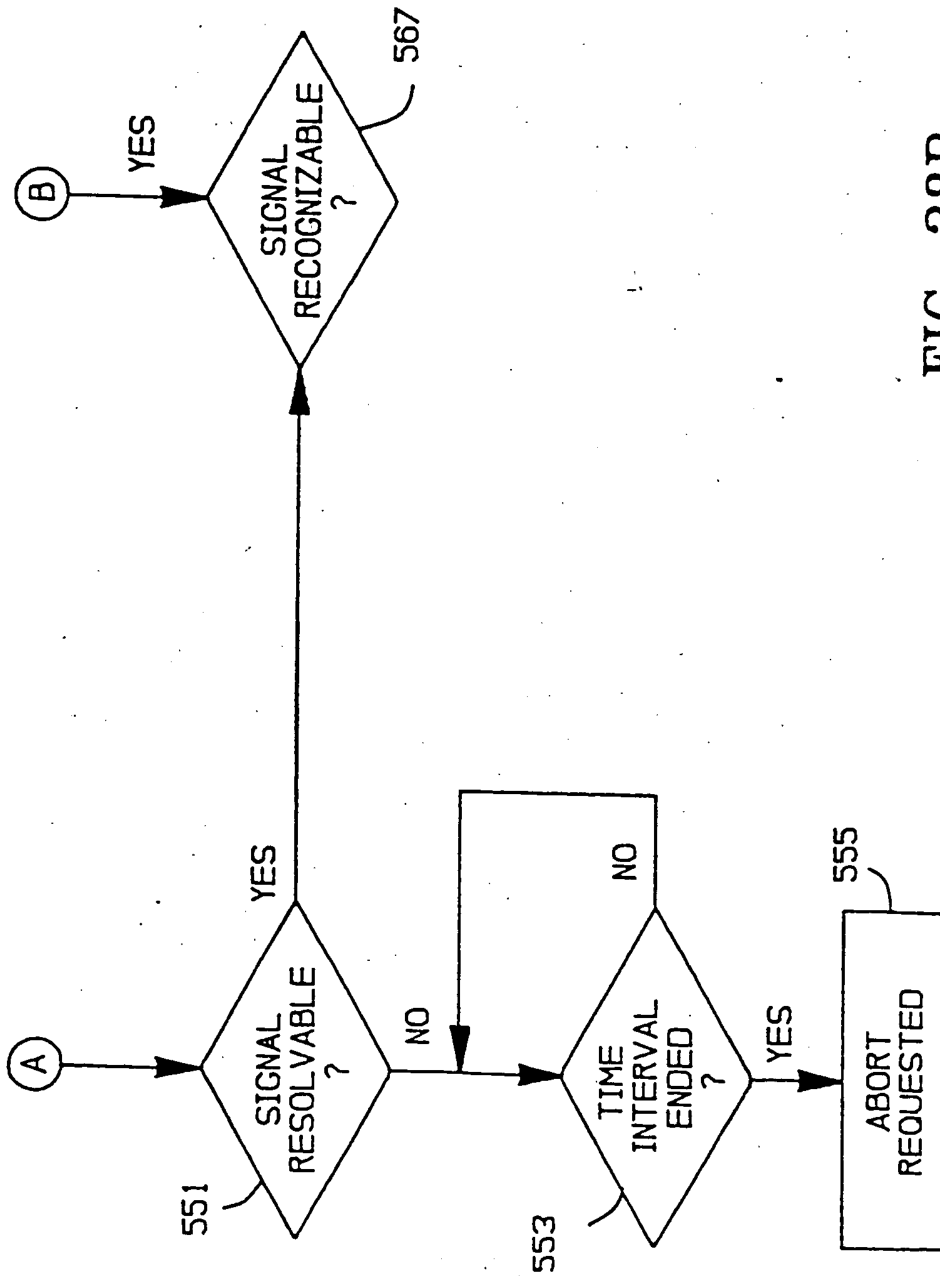

A
SIGNAL RESOLVABLE ?
551
YES
NO
TIME INTERVAL ENDED ?
553
NO
YES
ABORT REQUESTED
555
B
YES
SIGNAL RECOGNIZABLE ?
567

FIG. 28B

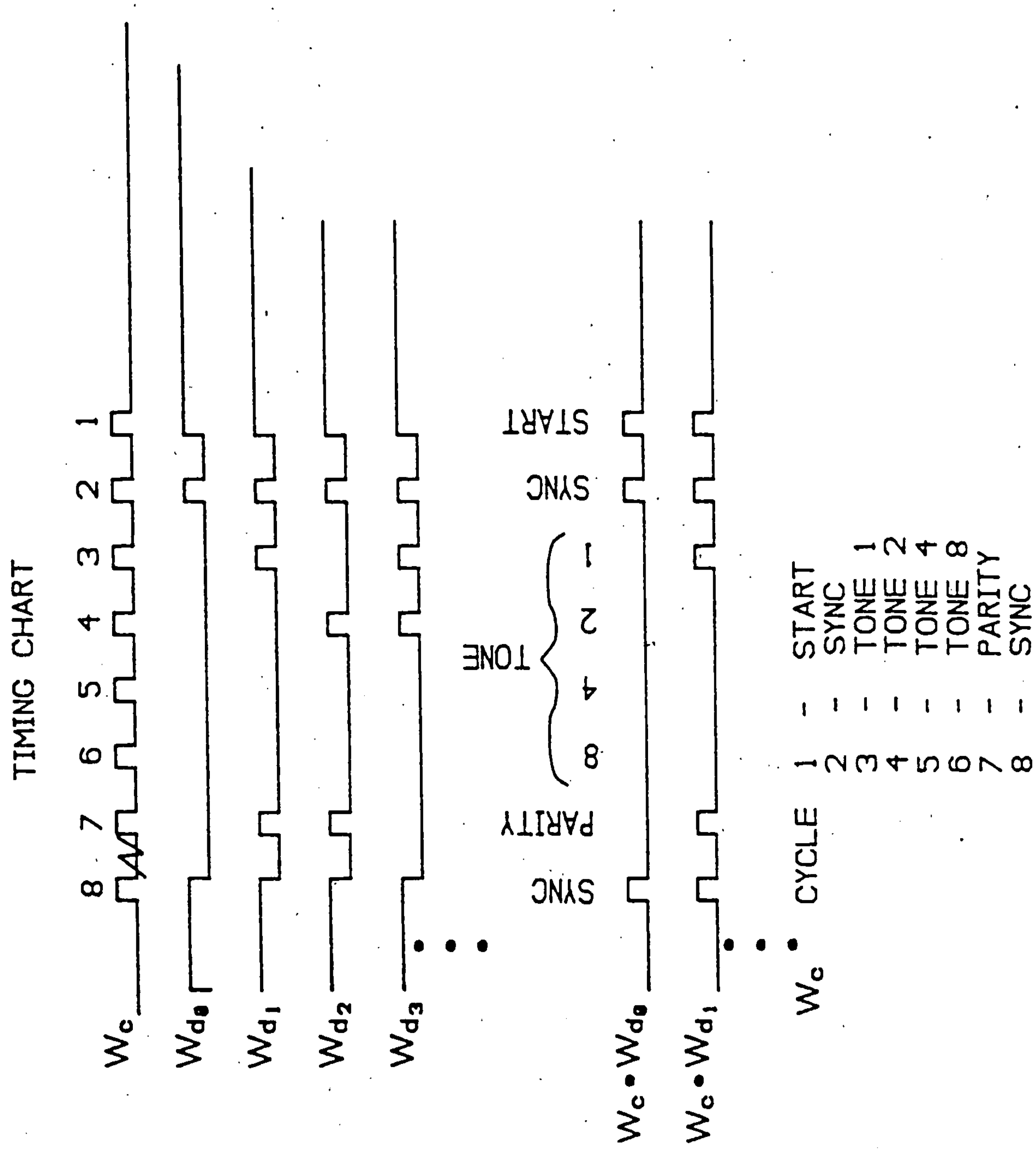


FIG. 29A
FIG. 29B
FIG. 29C
FIG. 29D
FIG. 29E
FIG. 29F
FIG. 29G

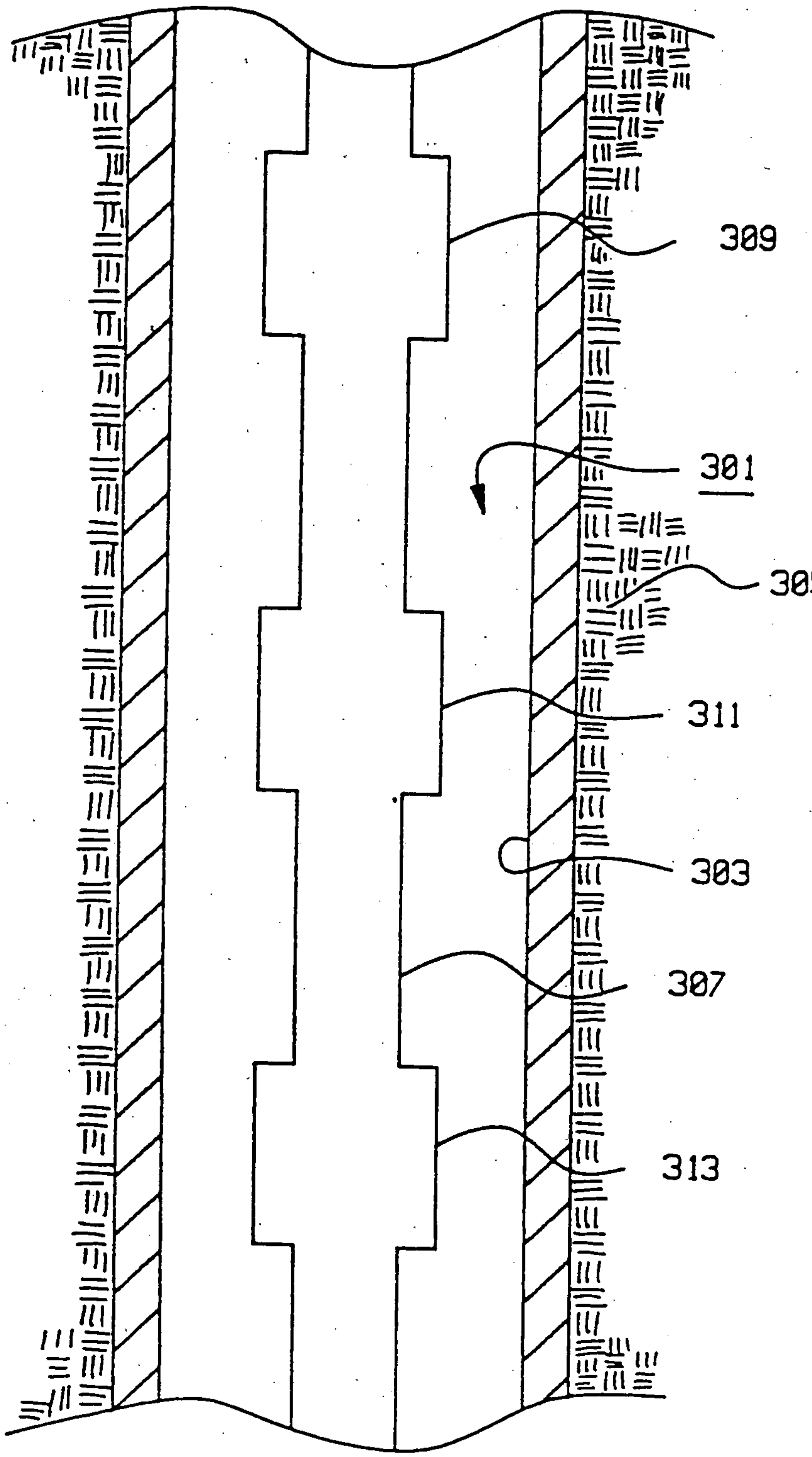


FIG. 30

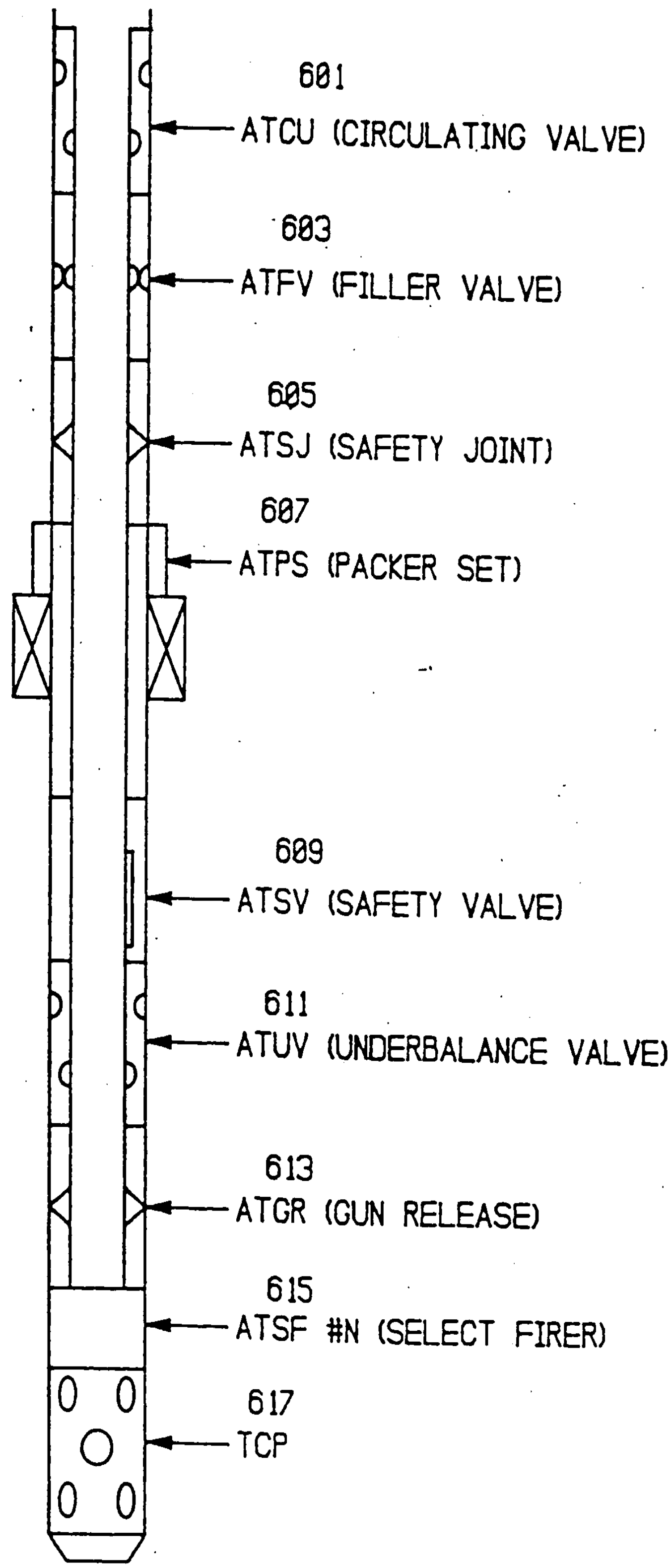

601
ATCU (CIRCULATING VALVE)
603
ATFV (FILLER VALVE)
605
ATSJ (SAFETY JOINT)
607
ATPS (PACKER SET)
609
ATSV (SAFETY VALVE)
611
ATUV (UNDERBALANCE VALVE)
613
ATGR (GUN RELEASE)
615
ATSF #N (SELECT FIRER)
617
TCP

FIG. 31

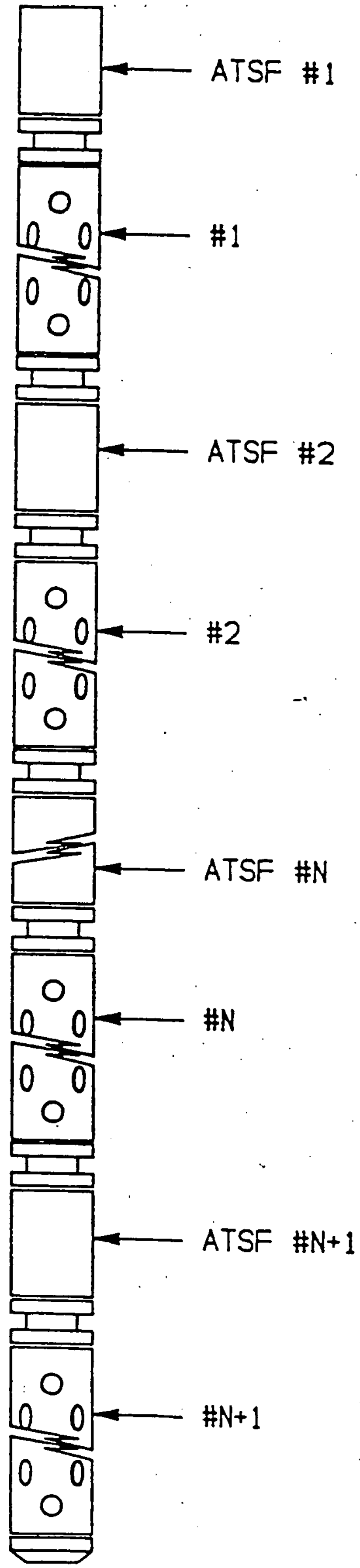


FIG. 32

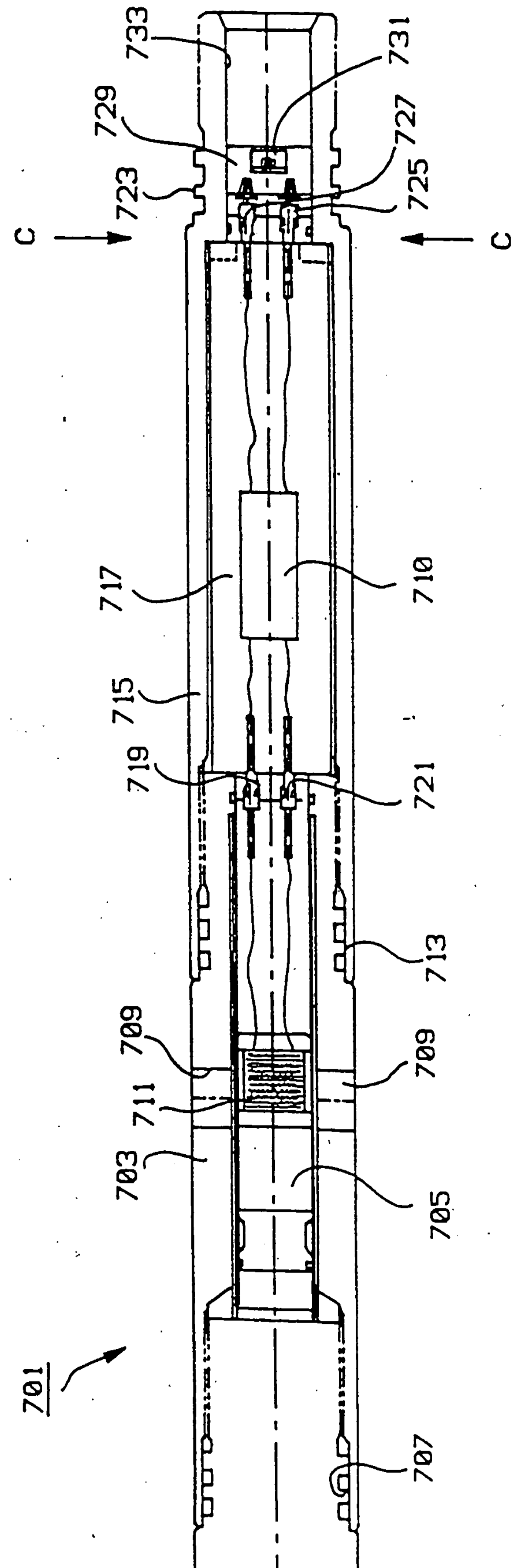
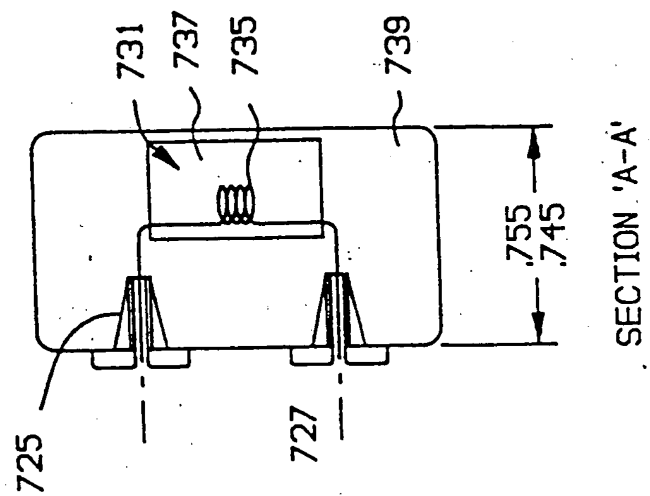
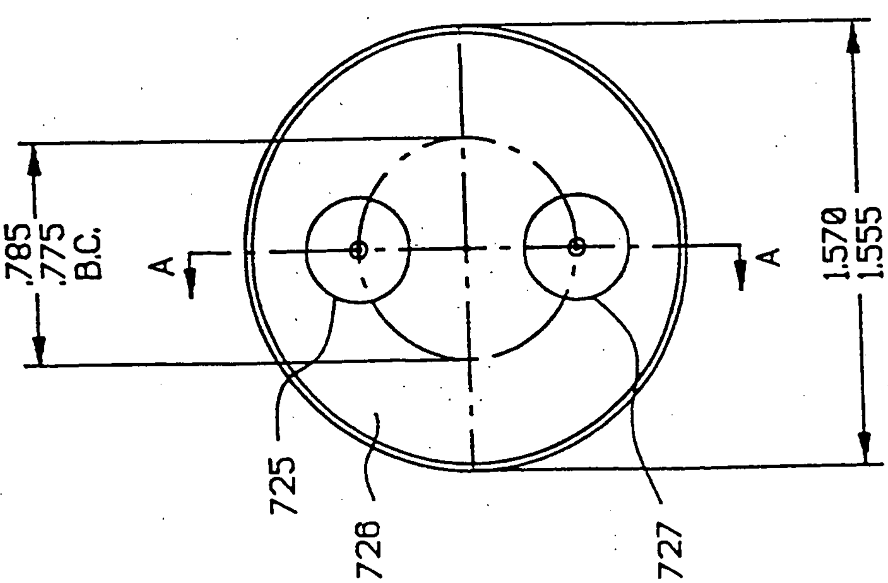

733
731
729
727
725
723
C
C
717
710
715
719
721
713
709
709
711
703
705
701
707

FIG. 33



731
737
735
739
.755
.745
SECTION 'A-A'
725
727

FIG. 35



.785
.775
B.C.
A
A
1.570
1.555
725
726
727

FIG. 34

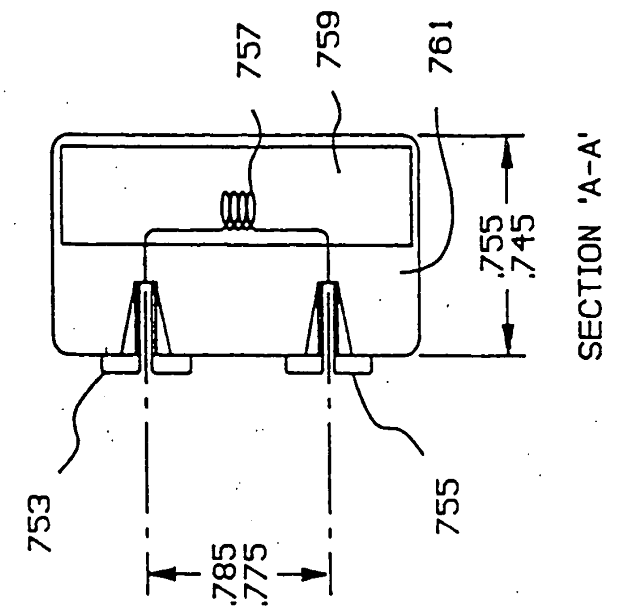

757
759
761
.755
.745
SECTION 'A-A'
753
755
.785
.775

FIG. 37

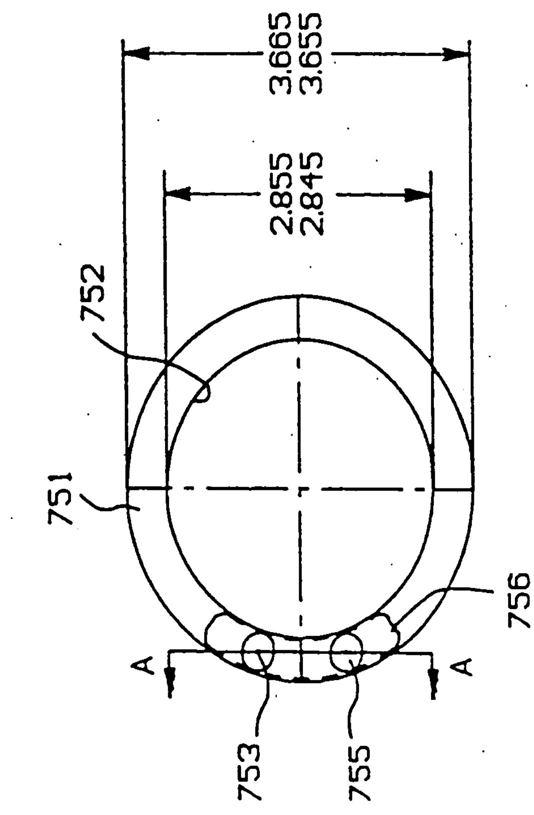
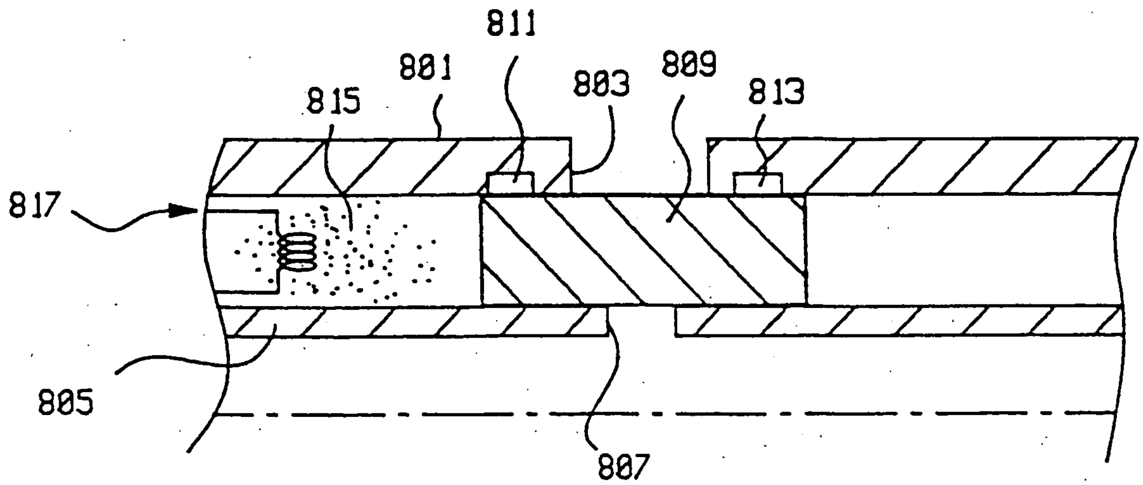
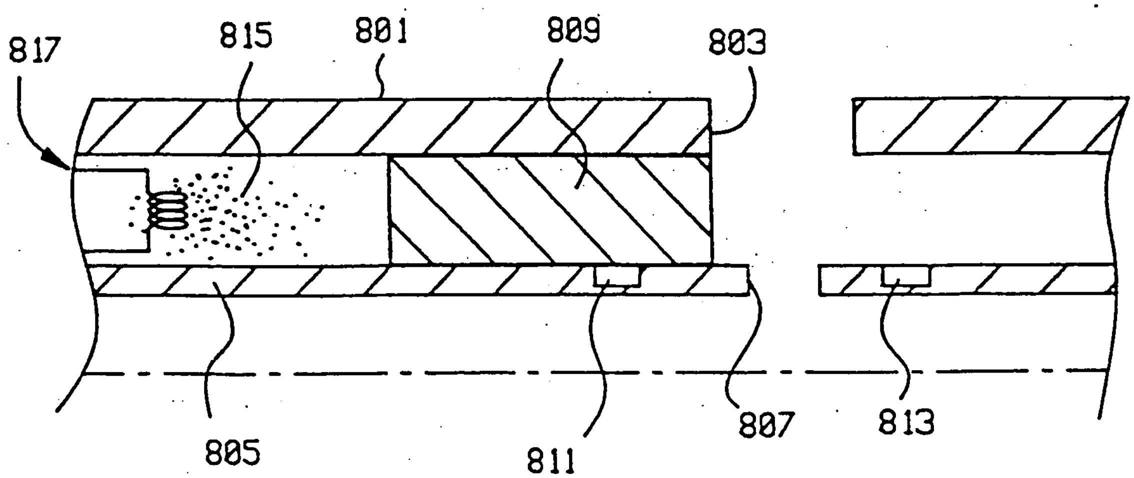

3.665
3.655
2.855
2.845
752
751
756
A
A
753
755

FIG. 36



811
801
815
803
809
813
817
805
807

FIG. 38



817
815
801
809
803
805
811
807
813

FIG. 39

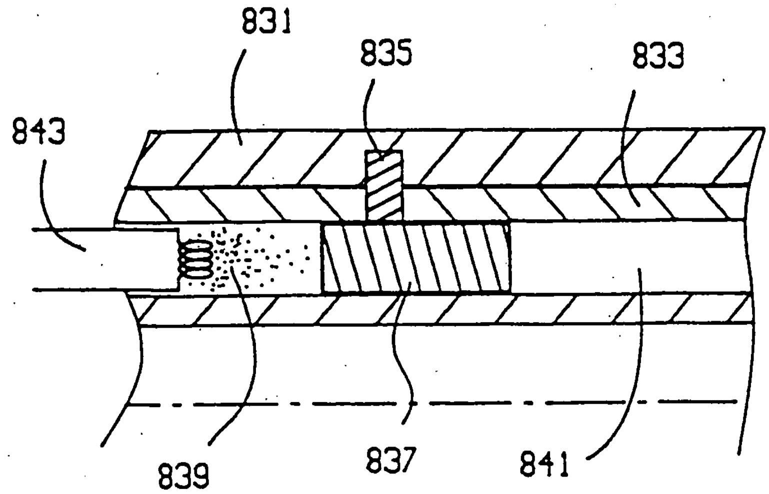


FIG. 40

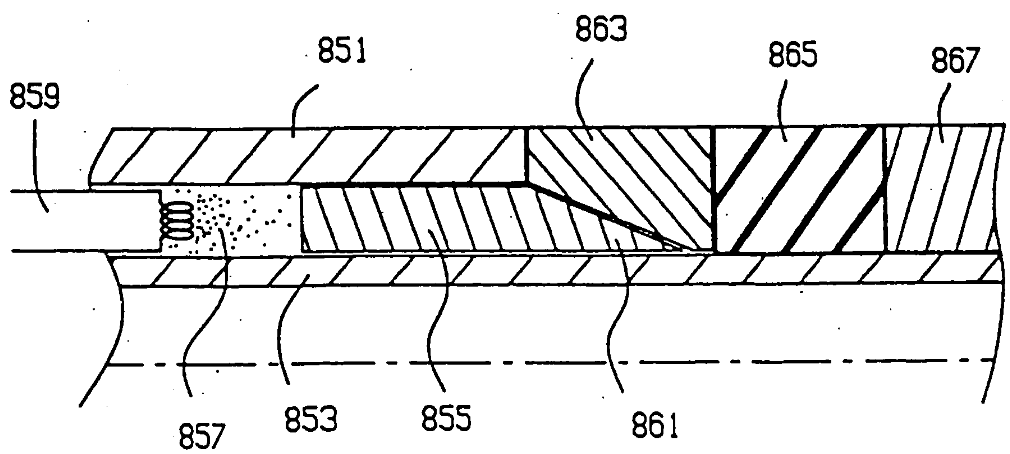


FIG. 41

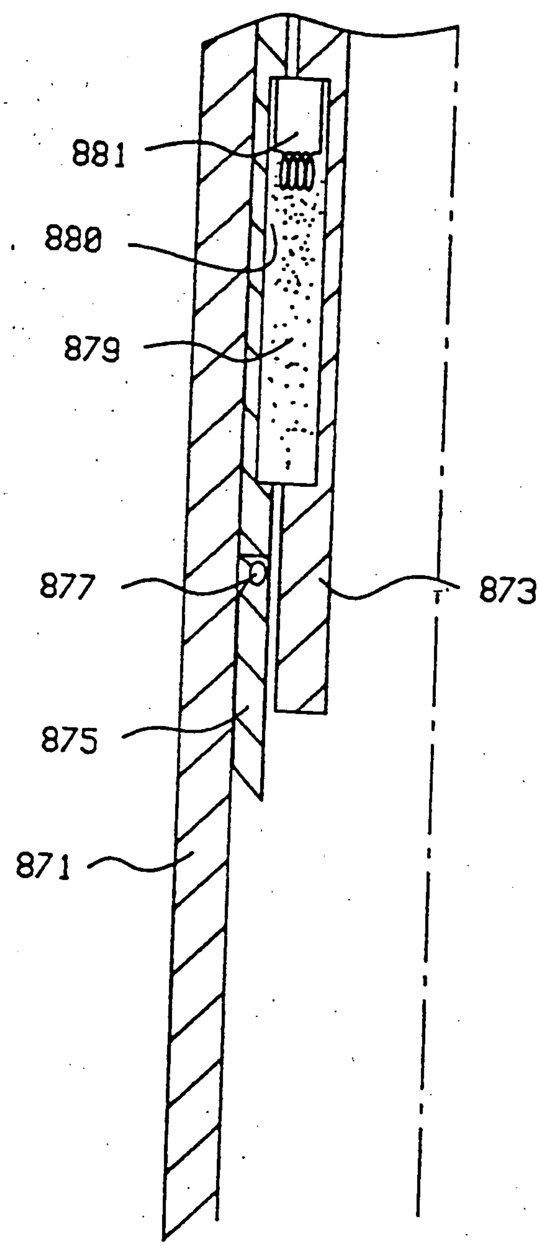


FIG. 42

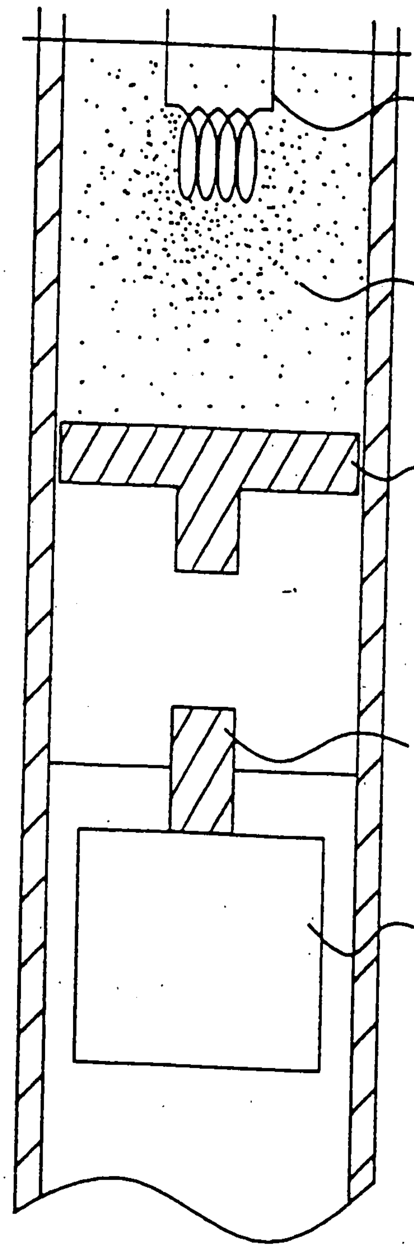


FIG. 43

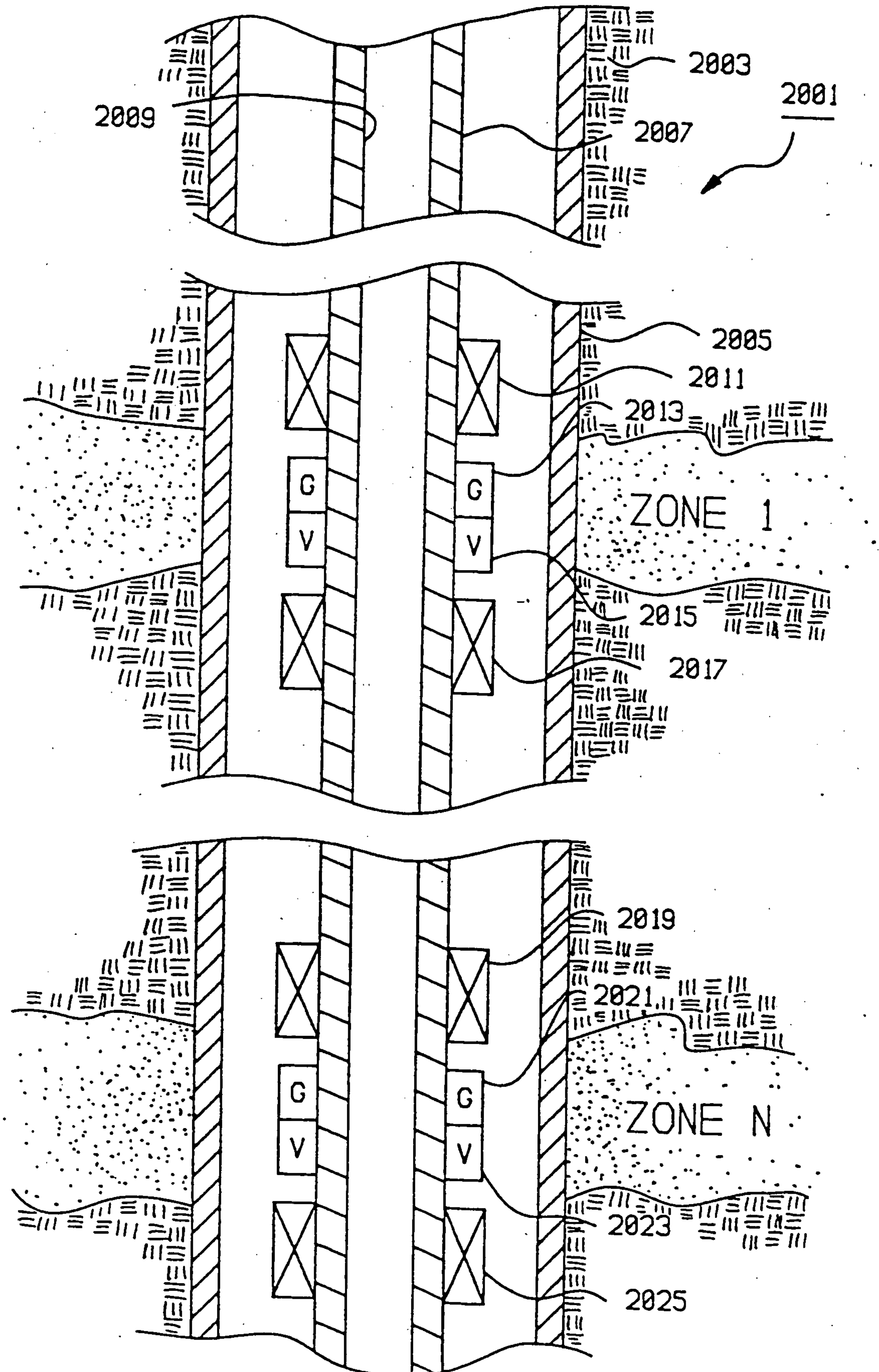

2003
2001
2009
2007
2005
2011
2013
ZONE 1
2015
2017
2019
2021
ZONE N
2023
2025
G
V

FIG. 44A

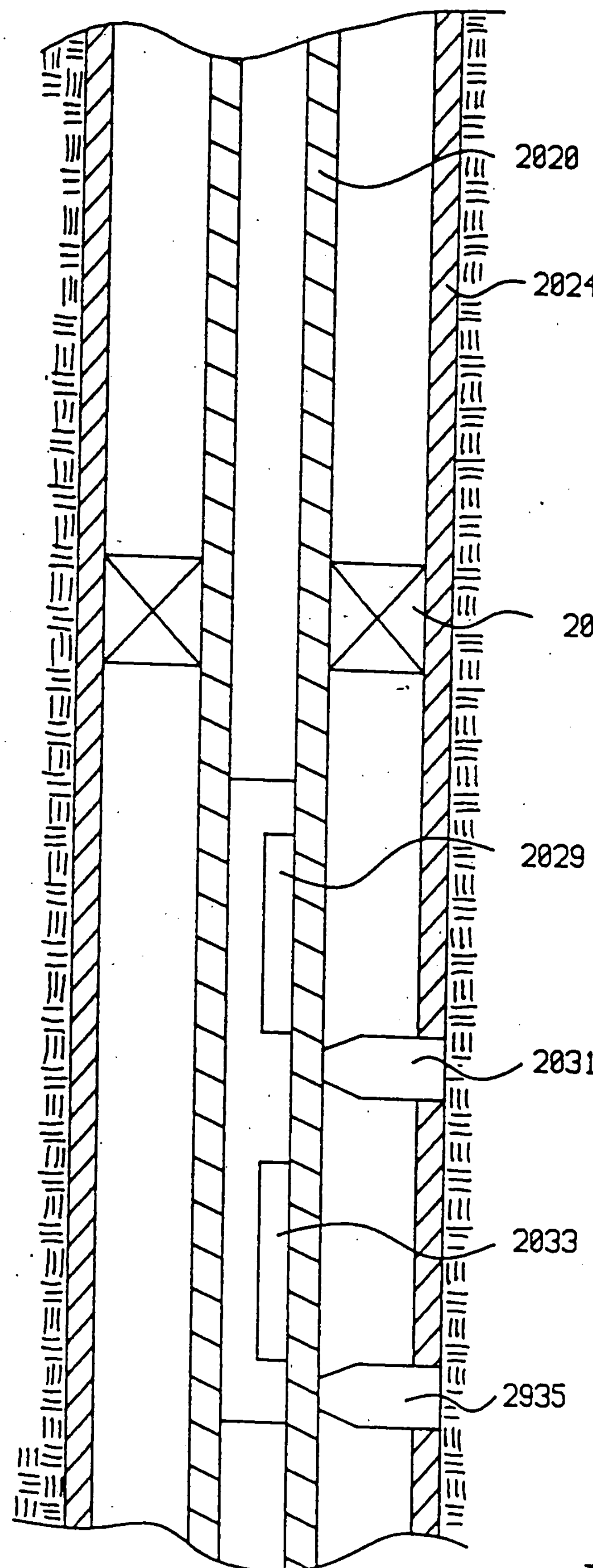


FIG. 44B

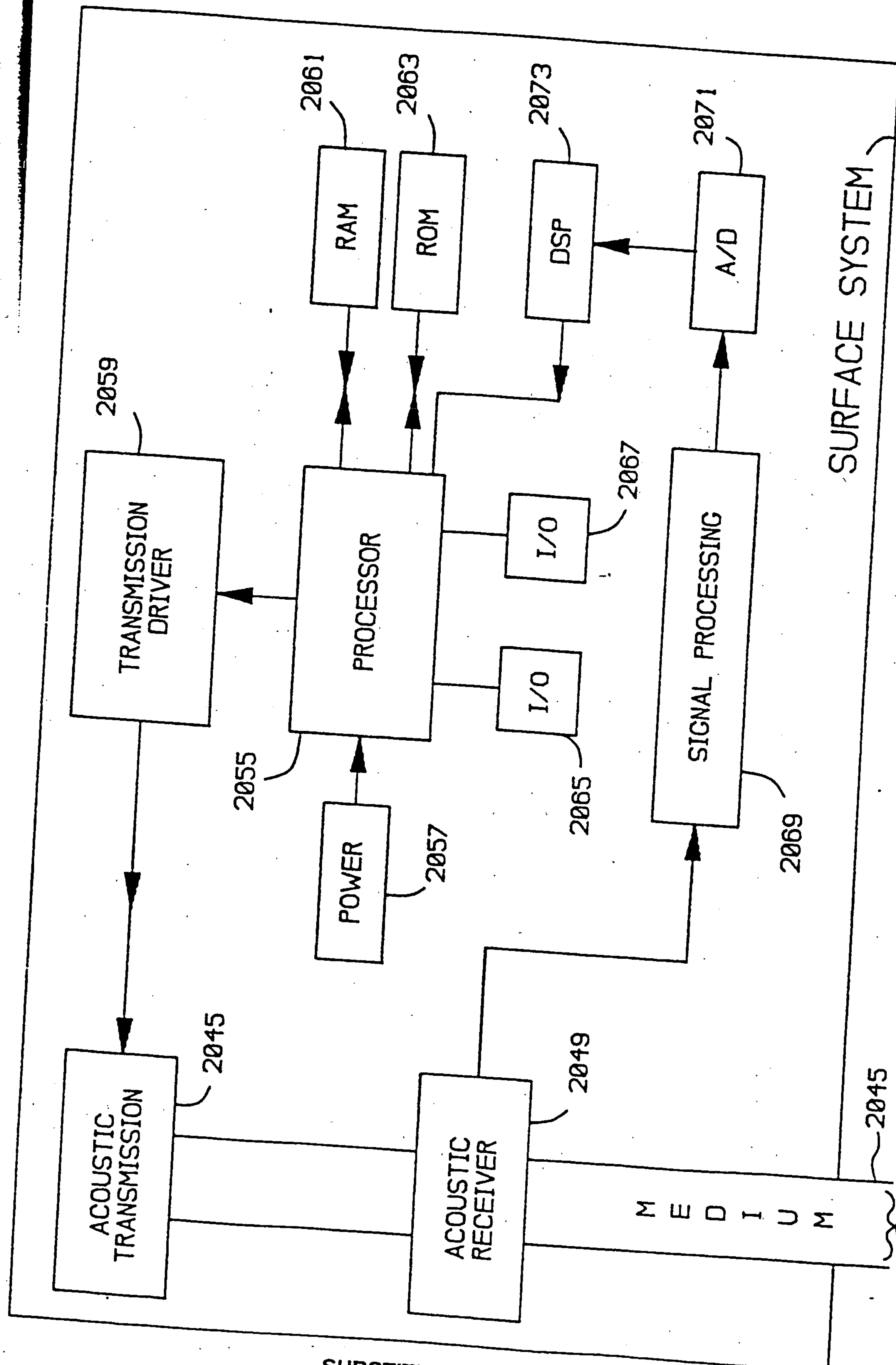

SURFACE SYSTEM
2041
RAM
2061
ROM
2063
DSP
2073
A/D
2071
TRANSMISSION DRIVER
2059
PROCESSOR
2055
I/O
2067
I/O
2065
SIGNAL PROCESSING
2069
POWER
2057
ACOUSTIC TRANSMISSION
2045
ACOUSTIC RECEIVER
2049
MEDIUM
2045
A

FIG. 45A

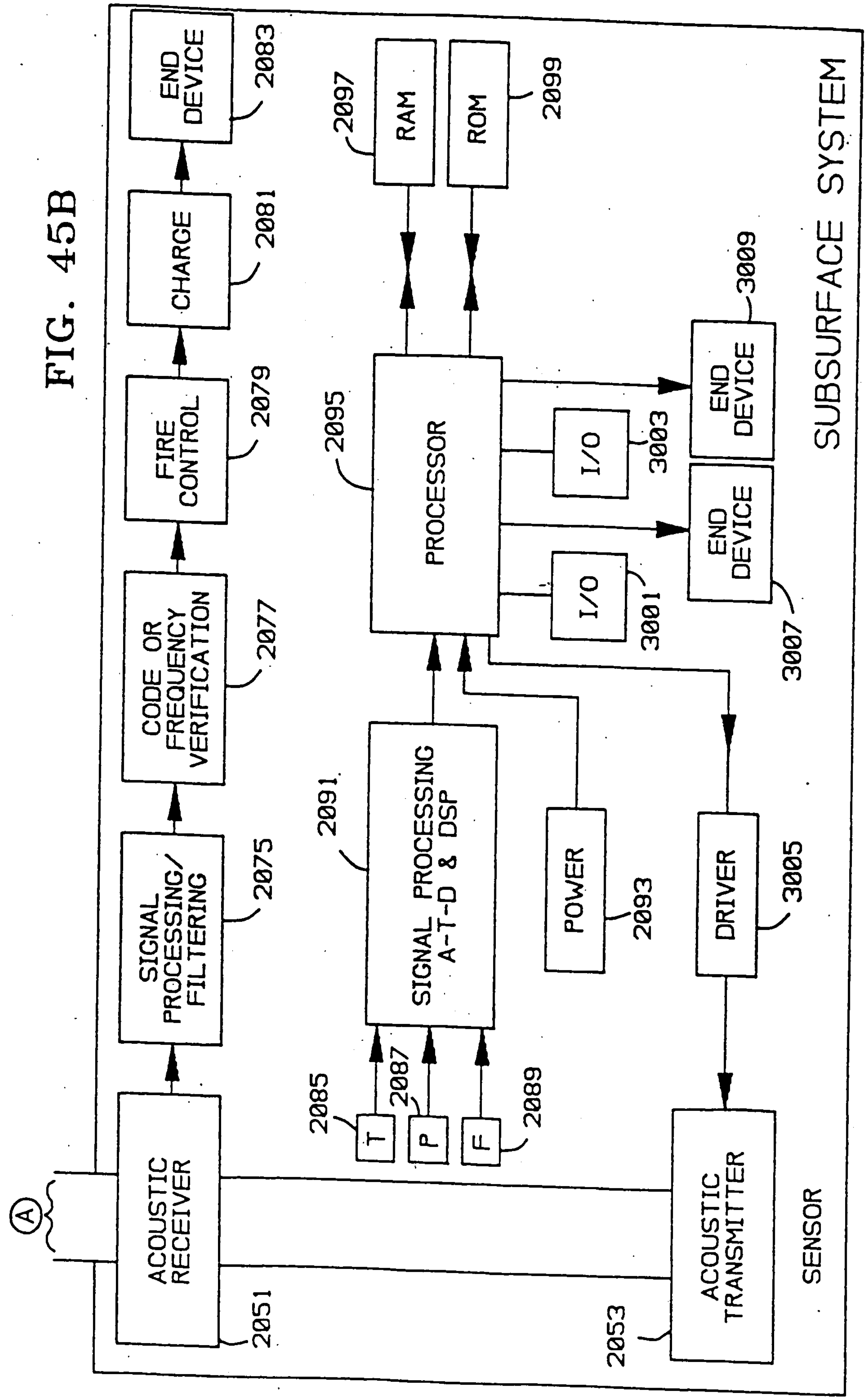

SUBSURFACE SYSTEM
A
ACOUSTIC RECEIVER
2051
SIGNAL PROCESSING/ FILTERING
2075
CODE OR FREQUENCY VERIFICATION
2077
FIRE CONTROL
2079
CHARGE
2081
END DEVICE
2083
T
2085
P
2087
F
2089
SIGNAL PROCESSING A-T-D & DSP
2091
POWER
2093
PROCESSOR
2095
RAM
2097
ROM
2099
I/O
3001
I/O
3003
DRIVER
3005
END DEVICE
3007
END DEVICE
3009
ACOUSTIC TRANSMITTER
2053
SENSOR

FIG. 45B

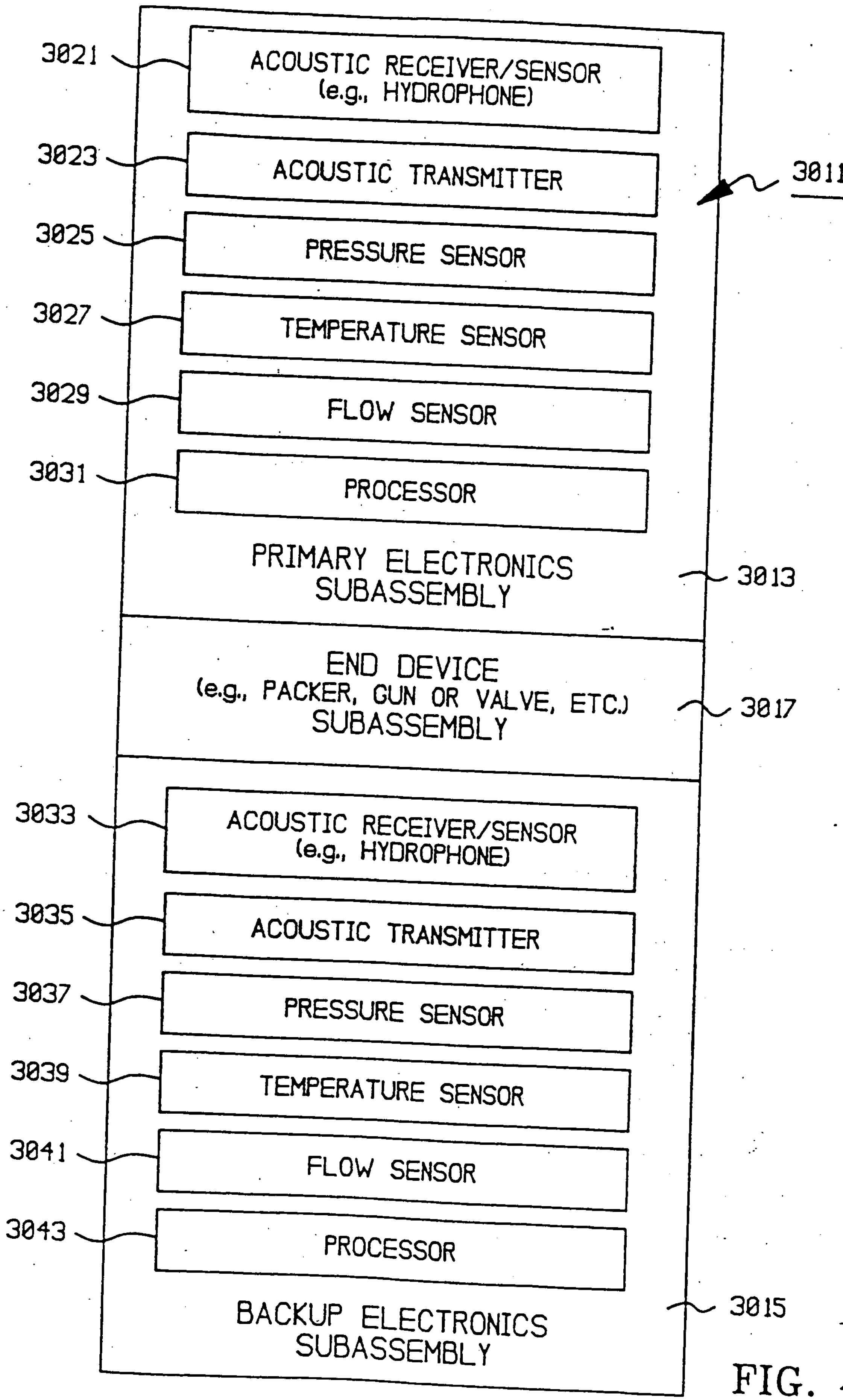

3021
ACOUSTIC RECEIVER/SENSOR (e.g., HYDROPHONE)
3023
ACOUSTIC TRANSMITTER
3011
3025
PRESSURE SENSOR
3027
TEMPERATURE SENSOR
3029
FLOW SENSOR
3031
PROCESSOR
PRIMARY ELECTRONICS SUBASSEMBLY
3013
END DEVICE (e.g., PACKER, GUN OR VALVE, ETC.) SUBASSEMBLY
3017
3033
ACOUSTIC RECEIVER/SENSOR (e.g., HYDROPHONE)
3035
ACOUSTIC TRANSMITTER
3037
PRESSURE SENSOR
3039
TEMPERATURE SENSOR
3041
FLOW SENSOR
3043
PROCESSOR
BACKUP ELECTRONICS SUBASSEMBLY
3015

FIG. 46

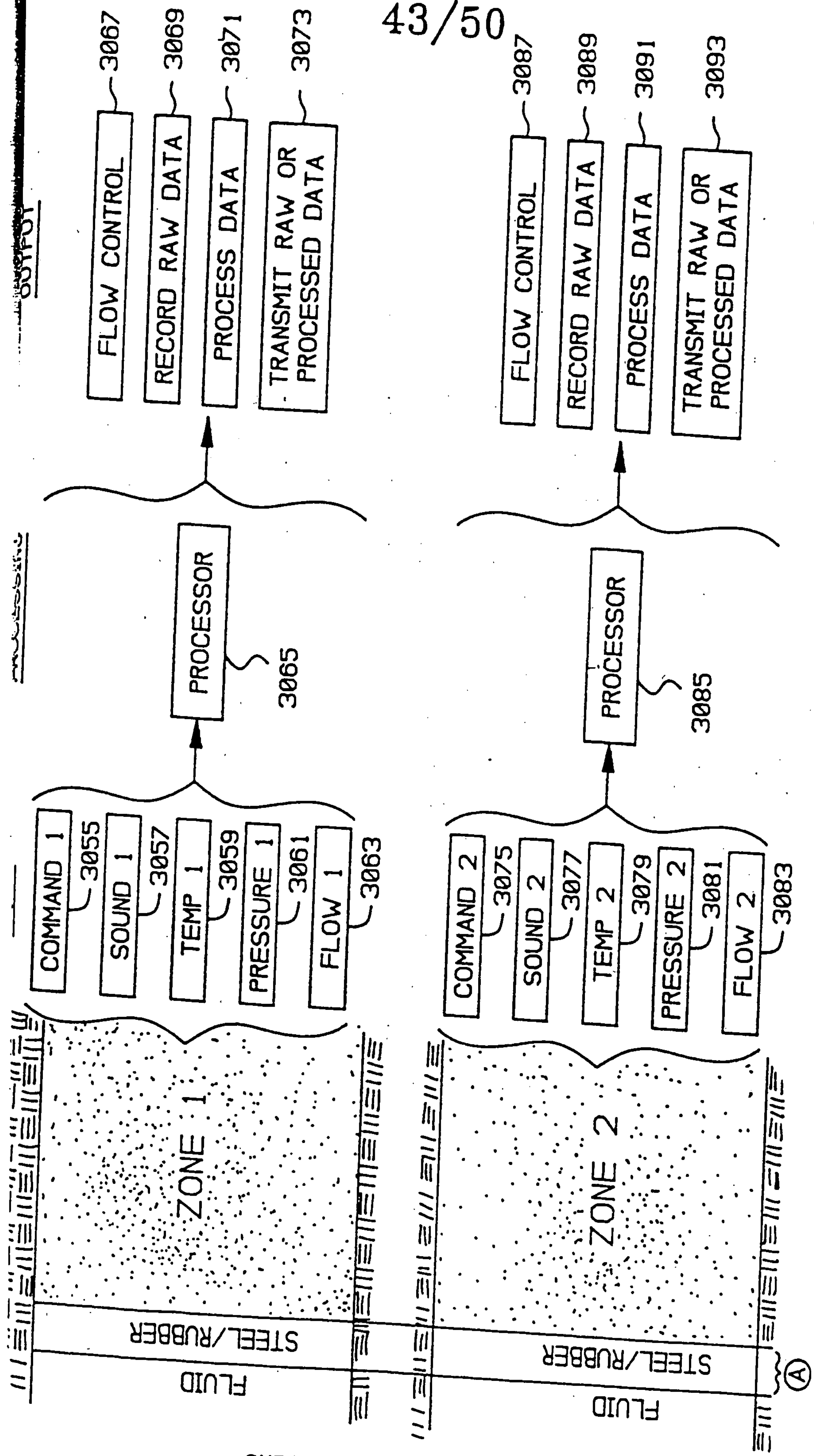

OUTPUT
PROCESSING
FLOW CONTROL
3067
RECORD RAW DATA
3069
PROCESS DATA
3071
TRANSMIT RAW OR PROCESSED DATA
3073
PROCESSOR
3065
COMMAND 1
3055
SOUND 1
3057
TEMP 1
3059
PRESSURE 1
3061
FLOW 1
3063
ZONE 1
STEEL/RUBBER
FLUID
FLOW CONTROL
3087
RECORD RAW DATA
3089
PROCESS DATA
3091
TRANSMIT RAW OR PROCESSED DATA
3093
PROCESSOR
3085
COMMAND 2
3075
SOUND 2
3077
TEMP 2
3079
PRESSURE 2
3081
FLOW 2
3083
ZONE 2
STEEL/RUBBER
FLUID
A

FIG. 47A

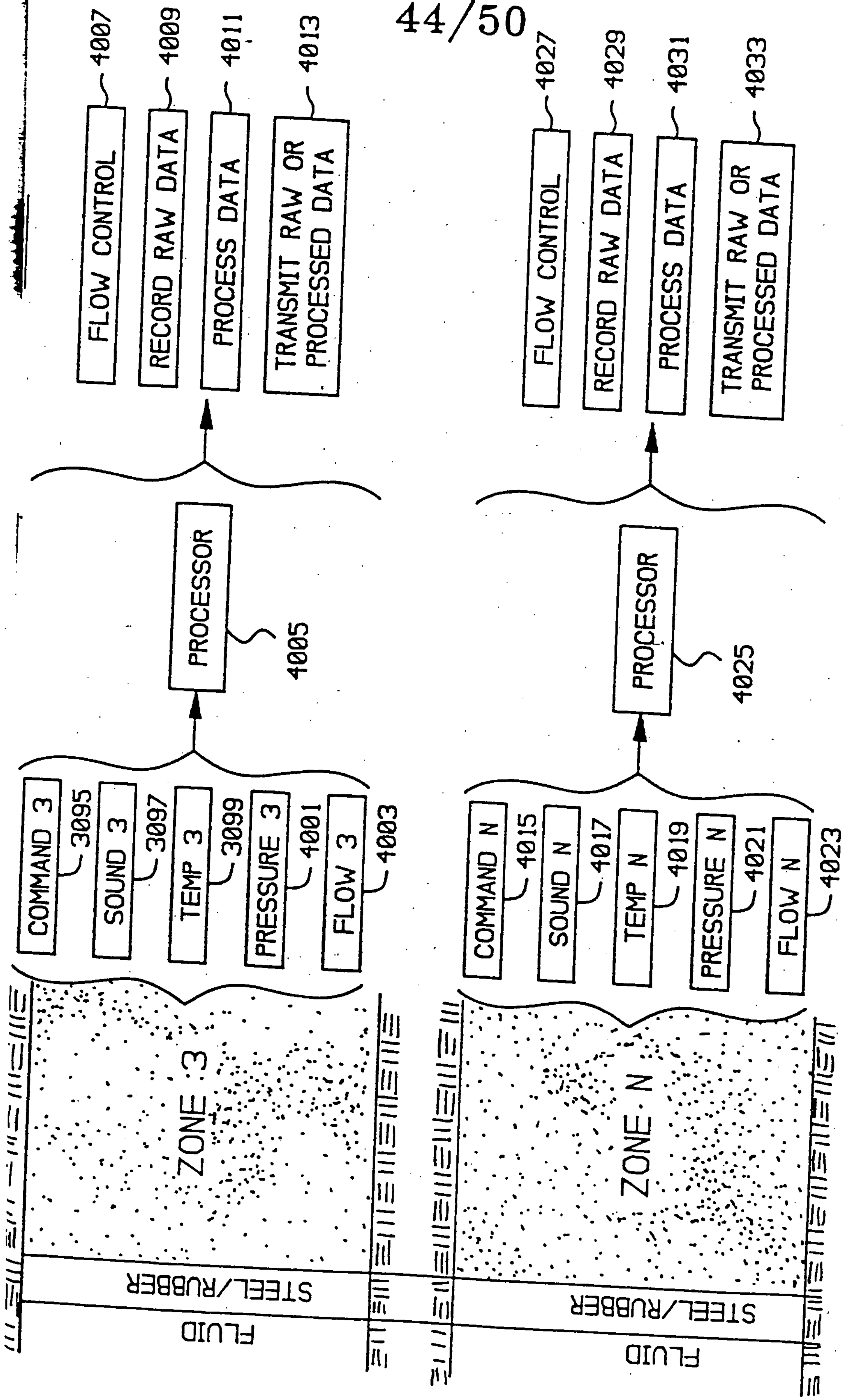

FLUID
STEEL/RUBBER
ZONE 3
COMMAND 3
3095
SOUND 3
3097
TEMP 3
3099
PRESSURE 3
4001
FLOW 3
4003
PROCESSOR
4005
FLOW CONTROL
4007
RECORD RAW DATA
4009
PROCESS DATA
4011
TRANSMIT RAW OR PROCESSED DATA
4013
FLUID
STEEL/RUBBER
ZONE N
COMMAND N
4015
SOUND N
4017
TEMP N
4019
PRESSURE N
4021
FLOW N
4023
PROCESSOR
4025
FLOW CONTROL
4027
RECORD RAW DATA
4029
PROCESS DATA
4031
TRANSMIT RAW OR PROCESSED DATA
4033

FIG. 47B

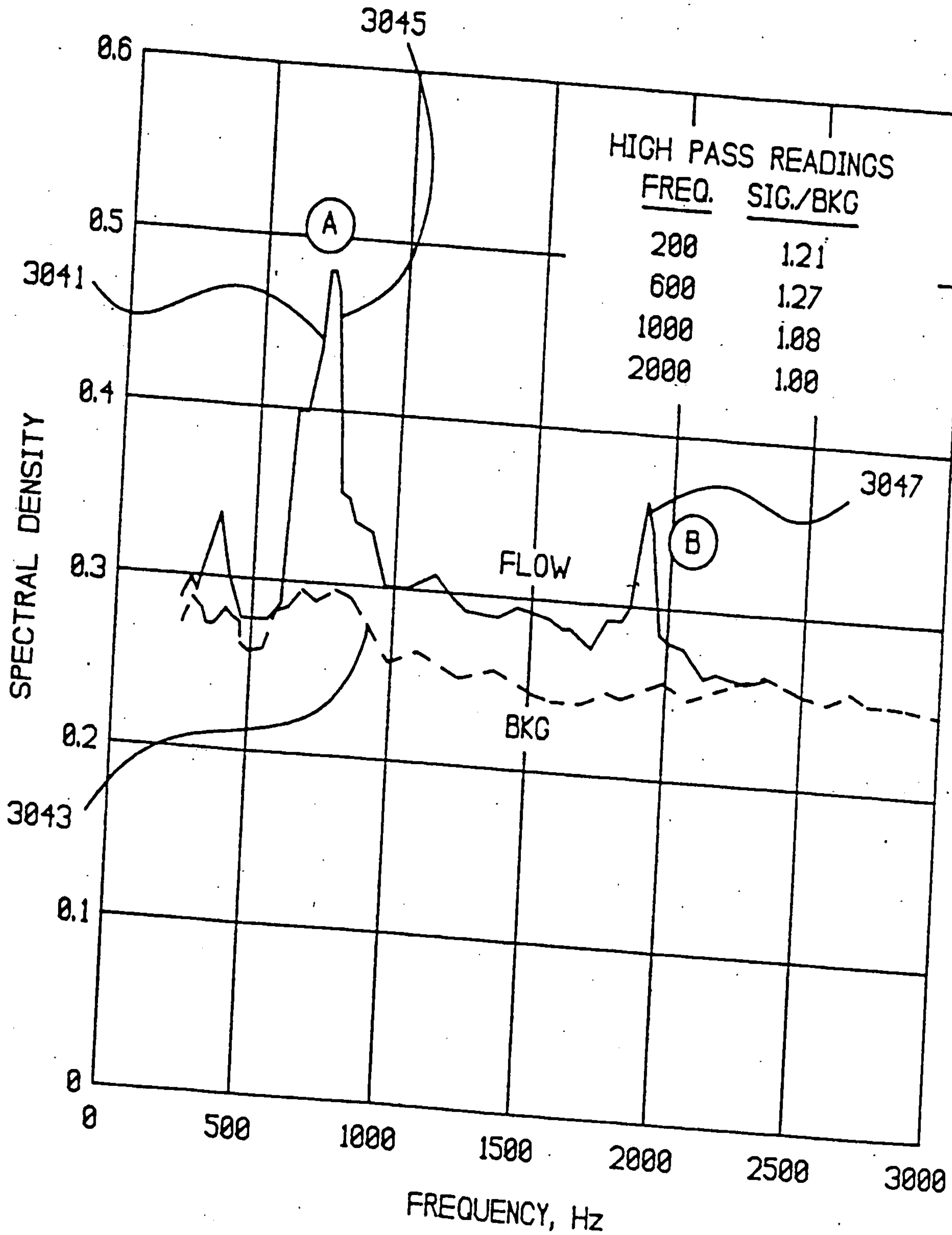

3045
0.6
HIGH PASS READINGS
FREQ.
SIG./BKG
200
1.21
600
1.27
1000
1.08
2000
1.00
0.5
A
3041
0.4
SPECTRAL DENSITY
3047
B
0.3
FLOW
BKG
0.2
3043
0.1
0
0
500
1000
1500
2000
2500
3000
FREQUENCY, Hz

FIG. 48

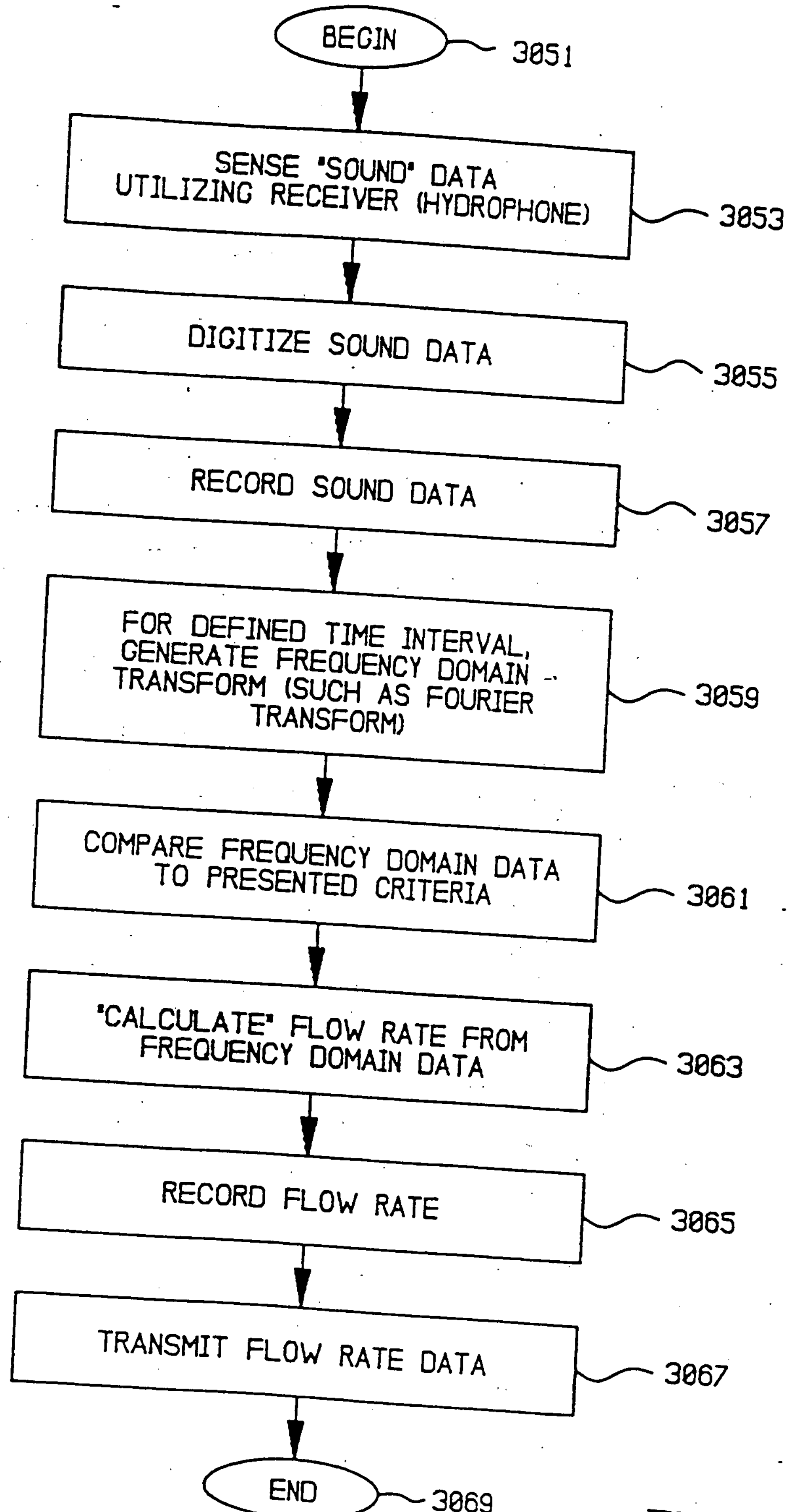

BEGIN
3051
SENSE "SOUND" DATA UTILIZING RECEIVER (HYDROPHONE)
3053
DIGITIZE SOUND DATA
3055
RECORD SOUND DATA
3057
FOR DEFINED TIME INTERVAL, GENERATE FREQUENCY DOMAIN TRANSFORM (SUCH AS FOURIER TRANSFORM)
3059
COMPARE FREQUENCY DOMAIN DATA TO PRESENTED CRITERIA
3061
"CALCULATE" FLOW RATE FROM FREQUENCY DOMAIN DATA
3063
RECORD FLOW RATE
3065
TRANSMIT FLOW RATE DATA
3067
END
3069

FIG. 49

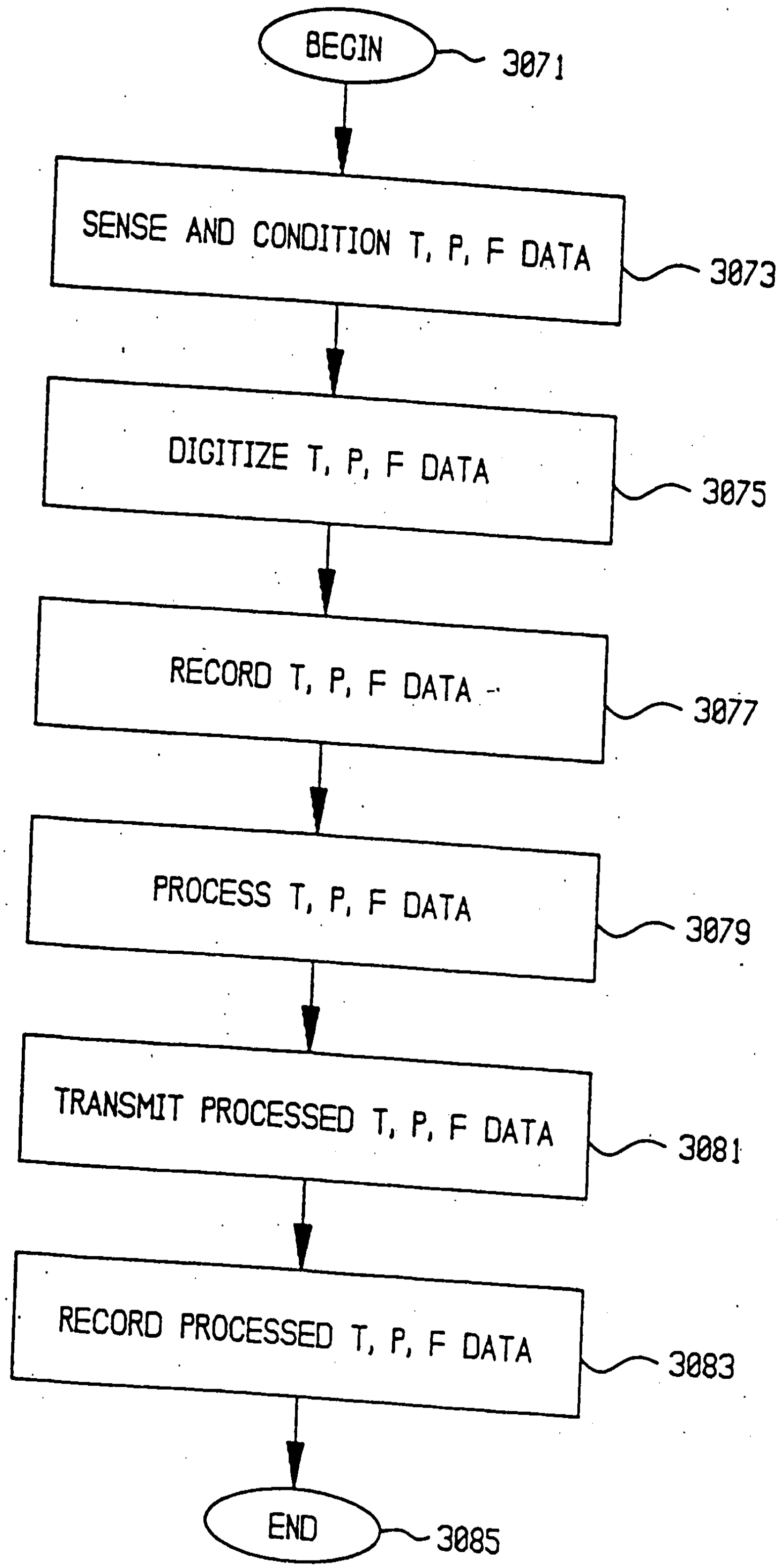

BEGIN
3071
SENSE AND CONDITION T, P, F DATA
3073
DIGITIZE T, P, F DATA
3075
RECORD T, P, F DATA
3077
PROCESS T, P, F DATA
3079
TRANSMIT PROCESSED T, P, F DATA
3081
RECORD PROCESSED T, P, F DATA
3083
END
3085

FIG. 50

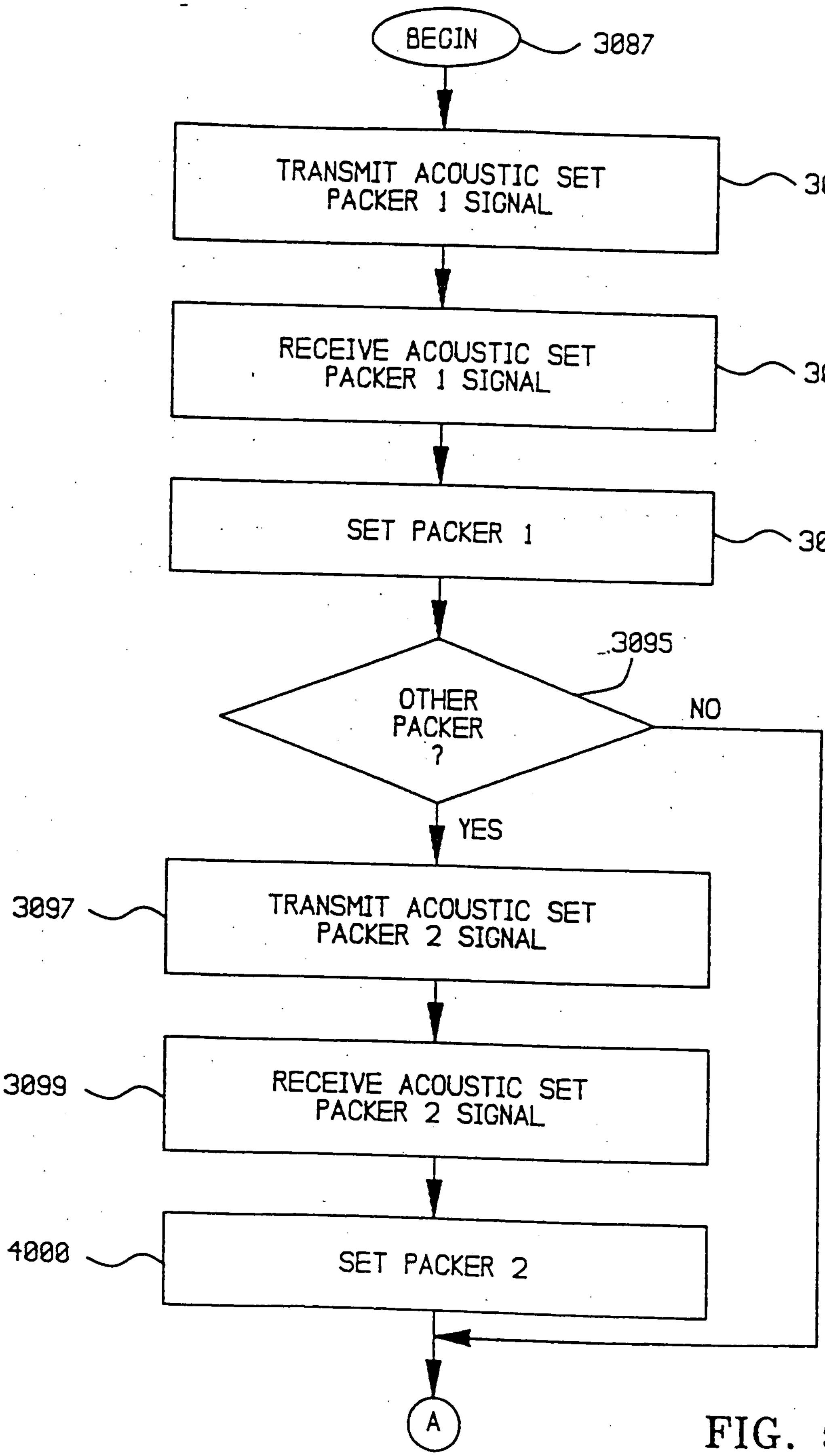

BEGIN
3087
TRANSMIT ACOUSTIC SET PACKER 1 SIGNAL
3089
RECEIVE ACOUSTIC SET PACKER 1 SIGNAL
3091
SET PACKER 1
3093
3095
OTHER PACKER ?
NO
YES
3097
TRANSMIT ACOUSTIC SET PACKER 2 SIGNAL
3099
RECEIVE ACOUSTIC SET PACKER 2 SIGNAL
4000
SET PACKER 2
A

FIG. 51A

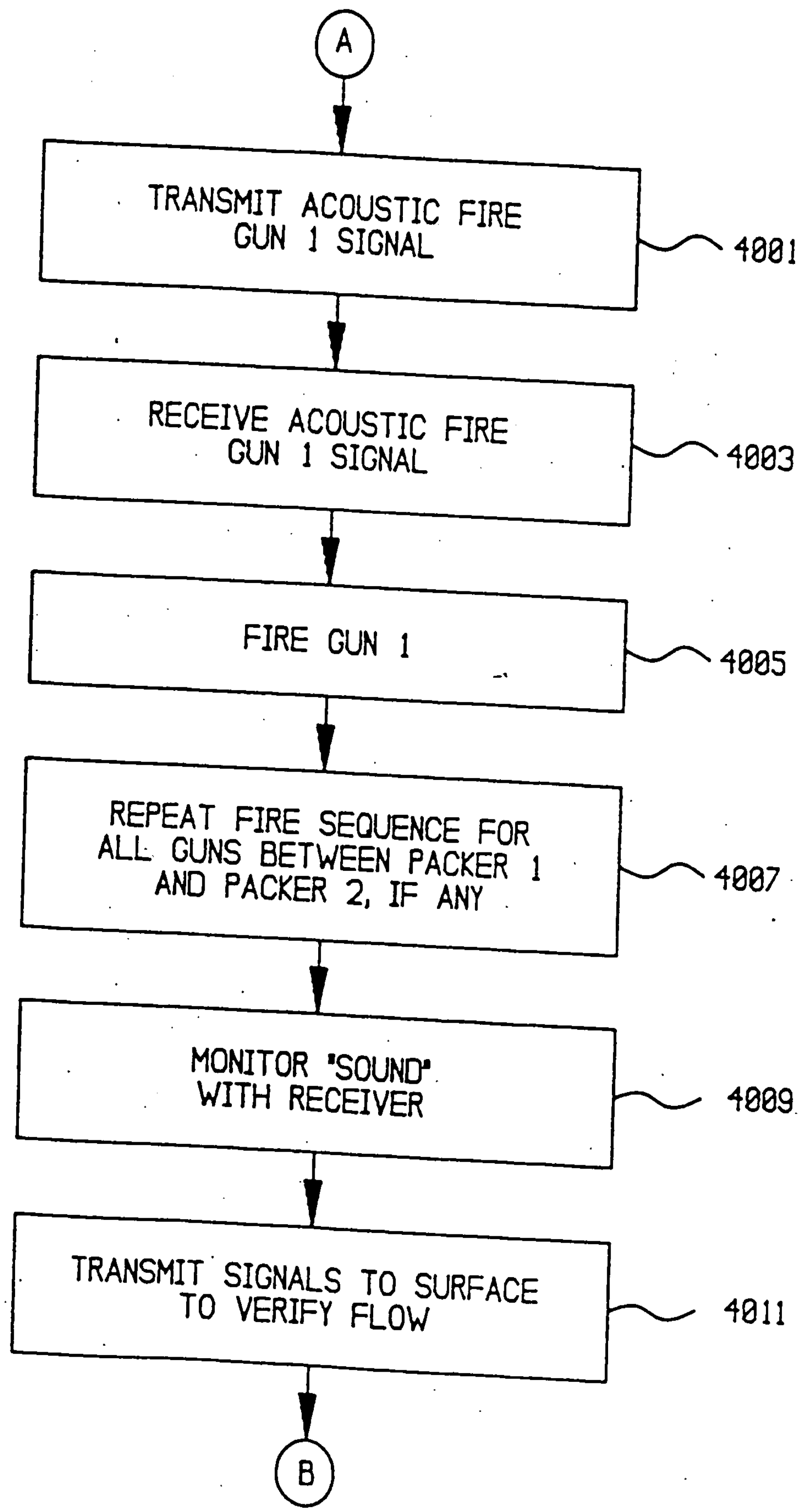

A
TRANSMIT ACOUSTIC FIRE GUN 1 SIGNAL
4001
RECEIVE ACOUSTIC FIRE GUN 1 SIGNAL
4003
FIRE GUN 1
4005
REPEAT FIRE SEQUENCE FOR ALL GUNS BETWEEN PACKER 1 AND PACKER 2, IF ANY
4007
MONITOR "SOUND" WITH RECEIVER
4009
TRANSMIT SIGNALS TO SURFACE TO VERIFY FLOW
4011
B

FIG. 51B

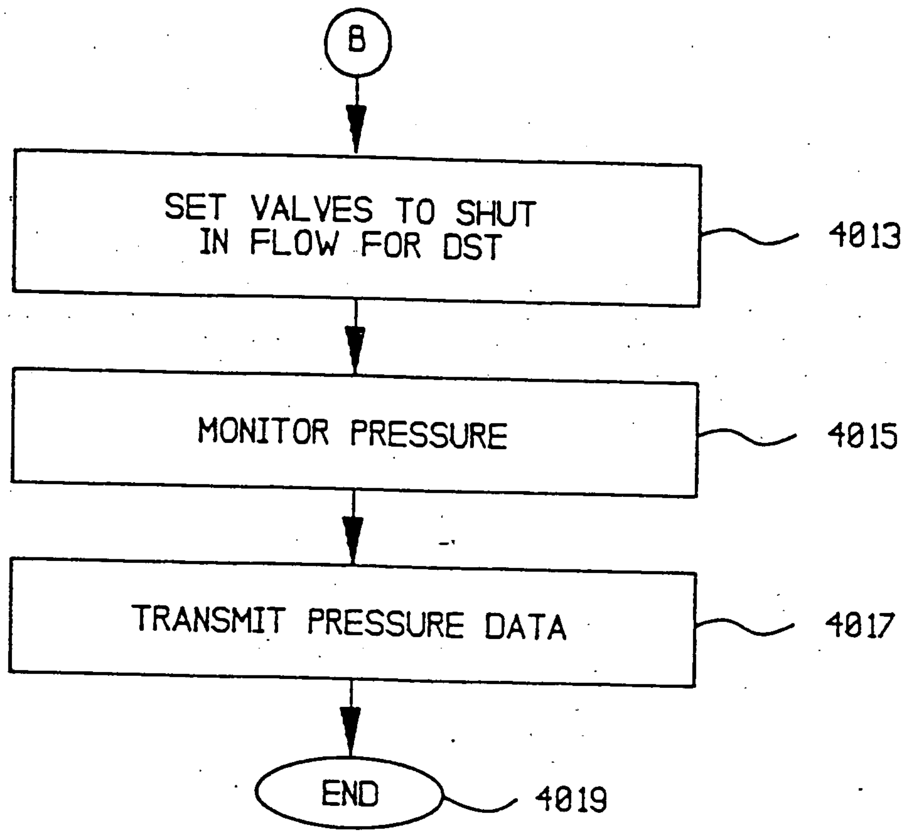

B
SET VALVES TO SHUT IN FLOW FOR DST
4013
MONITOR PRESSURE
4015
TRANSMIT PRESSURE DATA
4017
END
4019

FIG. 51C

INTERNATIONAL SEARCH REPORT

International Application No
PCT/US 96/16670

A. CLASSIFICATION OF SUBJECT MATTER
IPC 6 E21B47/18
According to International Patent Classification (IPC) or to both national classification and IPC

B. FIELDS SEARCHED
Minimum documentation searched (classification system followed by classification symbols)
IPC 6 E21B
Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched
Electronic data base consulted during the international search (name of data base and, where practical, search terms used)

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category *	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	EP 0 597 704 A (HALLIBURTON CO) 18 May 1994	1,3-7, 9-13, 15-34
Y	see column 1, line 35 - line 47 see column 2, line 45 - column 3, line 21 see column 9, line 42 - column 10, line 23 see column 11, line 33 - column 12, line 21 see column 14, line 12 - line 31 ---	2,8,14
Y	GB 2 281 424 A (BAKER HUGHES INC) 1 March 1995 see page 8, line 7 - page 9, line 26; claim 1.2.13.14 ---	2,8,14
	-/--	

[X] Further documents are listed in the continuation of box C.

[X] Patent family members are listed in annex.

* Special categories of cited documents :

"A" document defining the general state of the art which is not considered to be of particular relevance

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"L" document which may throw doubts on priority claim(s) or which is cited to establish the publication date of another citation or other special reason (as specified)

"O" document referring to an oral disclosure, use, exhibition or other means

"P" document published prior to the international filing date but later than the priority date claimed

"T" later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention

"X" document of particular relevance; the claimed invention cannot be considered novel or cannot be considered to involve an inventive step when the document is taken alone

"Y" document of particular relevance; the claimed invention cannot be considered to involve an inventive step when the document is combined with one or more other such documents, such combination being obvious to a person skilled in the art.

"&" document member of the same patent family

Date of the actual completion of the international search	Date of mailing of the international search report
3 March 1997	07.03.97
Name and mailing address of the ISA	Authorized officer
European Patent Office, P.B. 5818 Patentlaan 2 NL - 2280 HV Rijswijk Tel. (+31-70) 340-2040, Tx. 31 651 epo nl, Fax (+31-70) 340-3016	Haasbroek, J

INTERNATIONAL SEARCH REPORT

Information on patent family members

International Application No
PCT/US 96/16670

Patent document cited in search report	Publication date	Patent family member(s)	Publication date
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		CA 1119686 A	09-03-82
		DE 2721023 A	01-12-77
		EG 13329 A	30-06-81
		FR 2351549 A	09-12-77
		GB 1579488 A	19-11-80
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		OA 5657 A	30-04-81